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Oil sands geology – Athabasca deposit north

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Maps (in pocket)

Abstract

The study area encompasses the northern part of the Athabasca Wabiskaw-McMurray oil sands deposit, from townships 91 to 104 and ranges 6 to 20 west of the fourth meridian. Most of the bitumen reserves in the deposit are contained in laterally discontinuous, upward-fining channel sand bodies in the McMurray Formation. In the western part of the study area, significant reserves occur in laterally extensive marine bar sands at the top of the McMurray Formation and at the base of the overlying Clearwater Formation.

The McMurray Formation was deposited in a north-south trending depression on an erosional surface of Devonian limestone. The highly variable relief on this paleotopographic surface is the most important single control on the distribution of facies and reserves. Structural movement after deposition involved regional tilting to the northwest, on the axis of the Peace River Arch, and continued subsidence of local areas due to the solution of underlying Devonian evaporites.

Division of the McMurray Formation into the lower, middle and upper members was found to be valid over most of the study area. The lower member is of fluvial origin and fills in the deepest lows on the limestone surface, where the formation is greater than about 60 m thick. Coals and rooted zones are common near the top of the member. Rapid sea level rise during middle member time resulted in a lowering of gradient of the fluvial system and a change in channel type from the shallow (5 to 10 m), commonly coarse-grained channels of the lower member to deeper (20 to 30 m), narrow, sinuous, high suspended load channels of the middle member. The middle member channels were subject to invasion by salt water during low stage and were associated with a coastal plain mosaic of lakes and brackish bays. By upper member time, the open sea had invaded the northern and western parts of the study area, where upward-coarsening offshore marine bar sands are common.

Mapping of the reservoir characteristics with a control of four wells per township provides a regional overview as to the applicability of the various in situ recovery methods to different areas of the deposit. The most basic screening criteria for in situ recovery methods in Athabasca are: thickness of uninterrupted rich oil sand, overburden thickness and presence or absence of bottom water sands. Mapping of these screening criteria show that the areas of the deposit suitable for a particular process may be very limited.

Introduction

With an estimated 146 billion m^3 (918 billion barrels) of bitumen in place (Energy Resources Conservation Board, 1981), the Athabasca Wabiskaw-McMurray oil sands deposit (figure 1) is the largest of Alberta's Cretaceous oil sands deposits and probably the largest single accumulation of oil in the world. Commercial oil production from the deposit is currently limited to two operating surface mines: Suncor and Syncrude (figure 1). The surface mineable area, comprising about 10 percent of the deposit's reserves, is situated along the valley of the Athabasca River north of Fort McMurray, where overlying Cretaceous formations have been eroded such that the oil sands are within 50 m of the surface (figures 1, 2). Ninety percent of the deposit's reserves are too deep to be surface mined and will require in situ processes for recovery.

General geology

Stratigraphy

Most of the reserves in the study area are contained within the Lower Cretaceous McMurray Formation, a dominantly continental sequence of uncemented sands and shales overlying an unconformity surface of Devonian limestone (figures 2, 3). The thickness of the formation, a function of the relief on the underlying unconformity, varies from over 150 m in the center of the deposit to zero in the west, where it pinches out against a paleotopographic ridge of Devonian limestone (figure 2).

The marine Clearwater Formation overlies the McMurray Formation (figures 2, 3). The Wabiskaw Member, a glauconitic sand at the base of the Clearwater Formation, contains significant reserves in the western part of the study area. In the east, only a thin interval of argillaceous, glauconitic Wabiskaw Member overlies the McMurray Formation (included with the McMurray Formation in figure 2).

The dominantly sandstone Grand Rapids Formation overlies the Clearwater Formation, which is dominantly marine shale (figures 2, 3). The contact between the Clearwater and Grand Rapids Formations is diachronous, and its placement subjective as a result of the interfingering nature of the facies (Badgley, 1952).

The McMurray Formation is stratigraphically equivalent to the Gething Formation of the Peace River area and the Dina of east-central Alberta and Saskatchewan (figure 3). The Wabiskaw Member of the Clearwater Formation is correlative with the Bluesky Formation of the Peace River area, the Cummings Member of the Lloydminster region and the Glauconitic Sandstone of central Alberta. See *Depositional environments and facies* for further discussion of age and stratigraphic relationships.

Mineralogy

Compared to the other Alberta oil sands deposits, the sediments of the Athabasca deposit have a very uniform, mature mineralogy. Sands of the McMurray Formation consist of 91 to 99 percent quartz and a few percent each of feldspar and rock fragments (Carrigy, 1963b; Nelson and Glaister, 1978; Knight *et al.*, 1981). The fines fraction ($< 44\ \mu$m) consists largely of silt (90 percent), with only about 10 percent clay minerals, mostly kaolinite and illite. With its low clay content and comparative lack of swelling clays, the composition of the McMurray Formation contrasts markedly with that of the other oil sands deposits (Nelson and Glaister, 1978). In the overlying Clearwater Formation, the appearance of sediment of volcanic origin signals a change in source area from the east to the Cordilleran region in the west (Williams, 1963; Mellon, 1967).

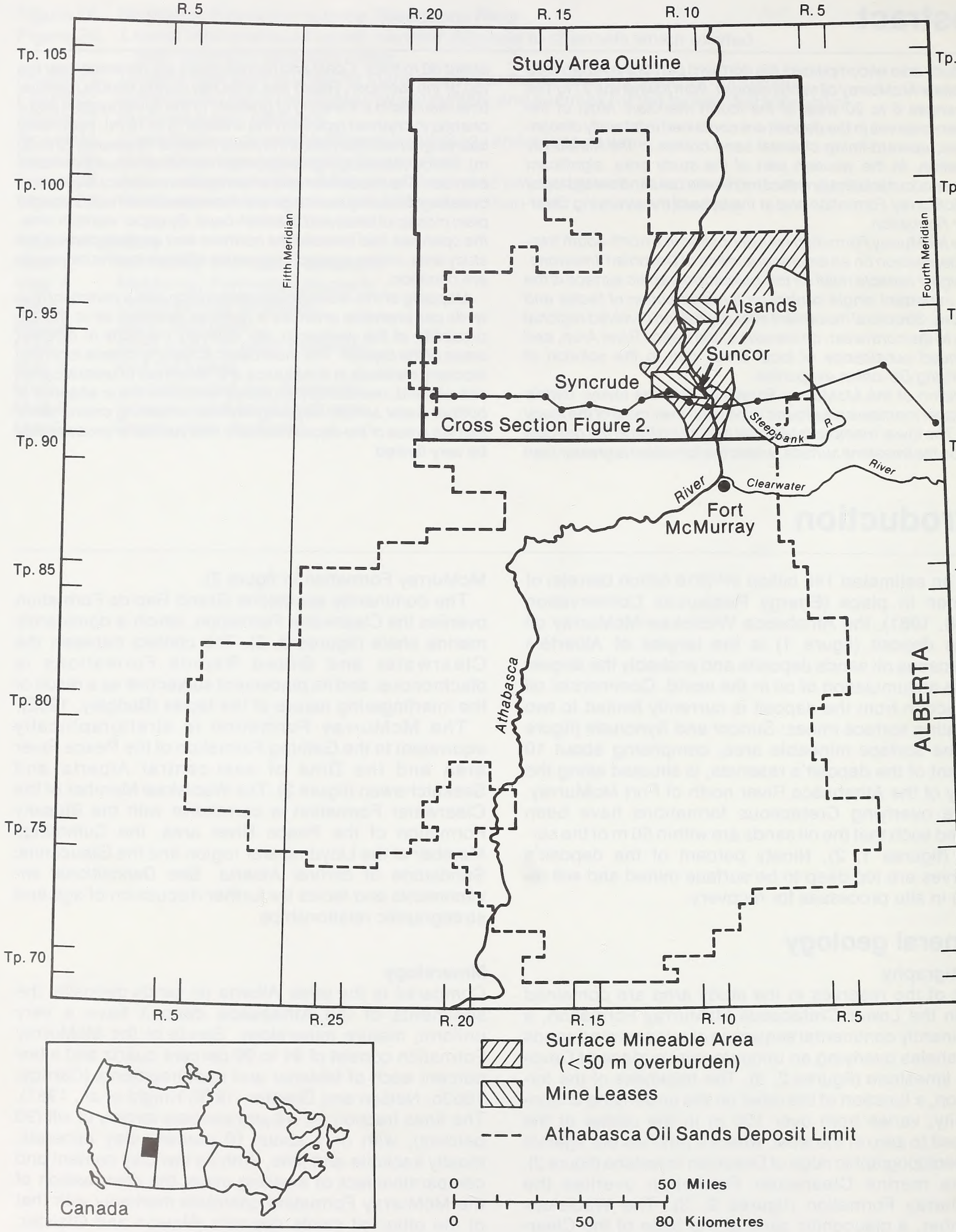


Figure 1. Index map showing location of study area and extent of the Athabasca Wabiskaw-McMurray oil sands deposit. Syncrude and Suncor are operating surface mines; the proposed Alsands project was cancelled but data from the lease area is referred to in the text.

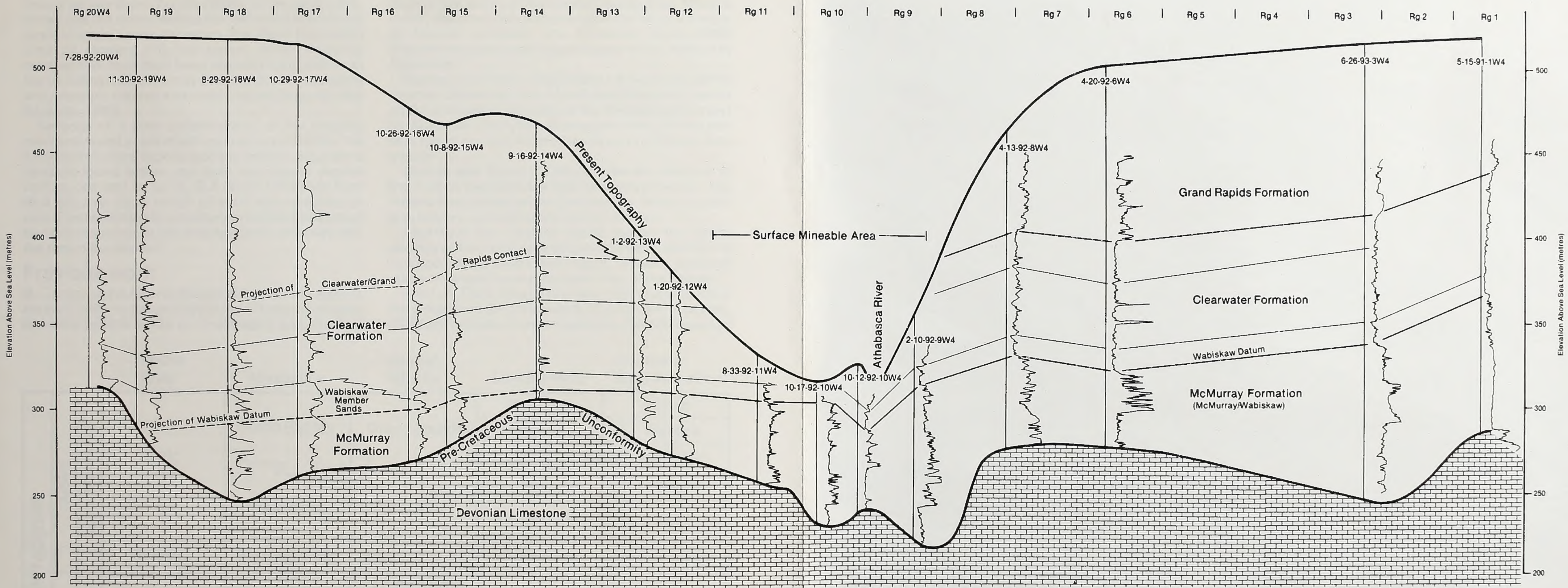
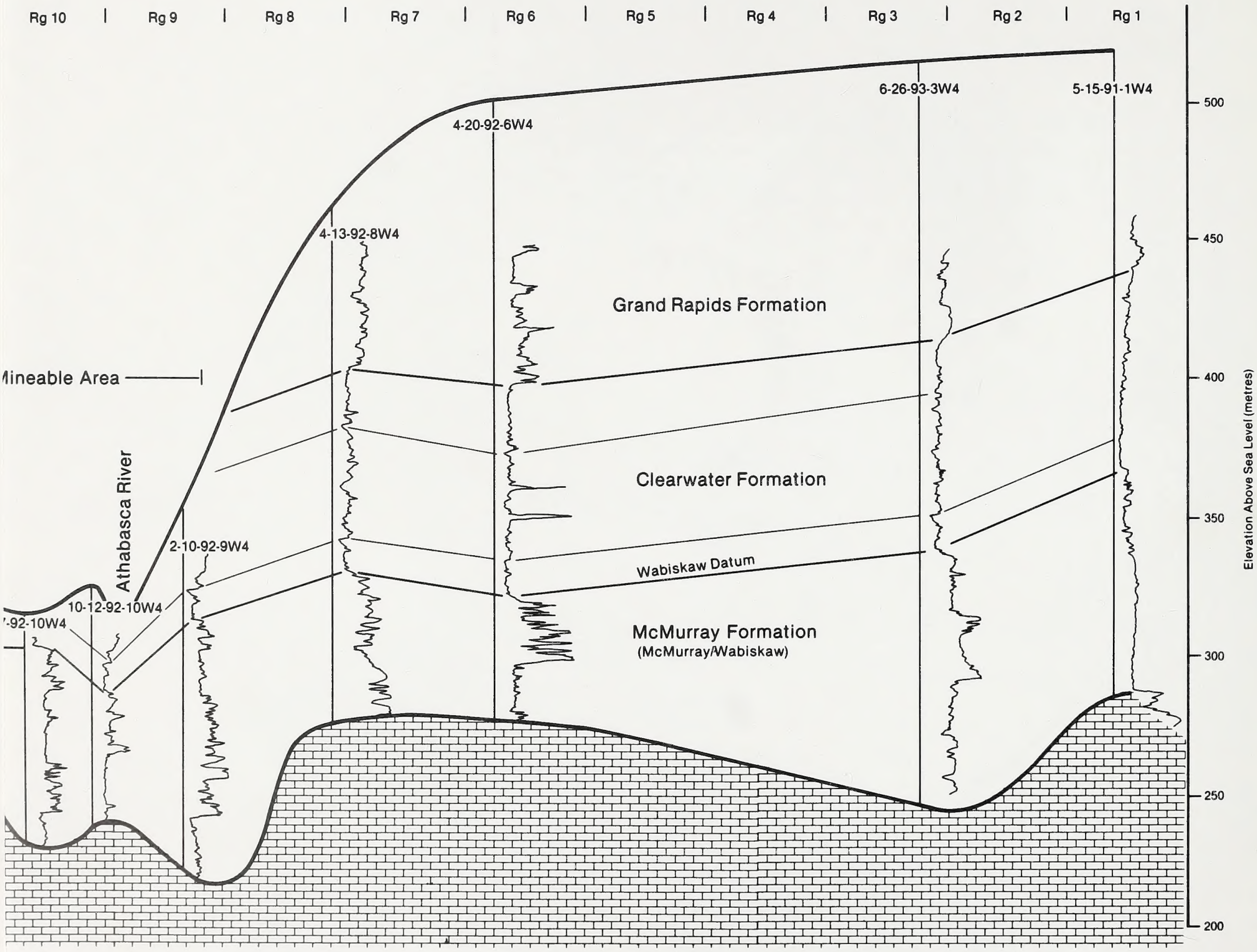


Figure 2. East-west structural cross section near southern edge of study area. Location shown on figure 1. The McMurray Formation shown here includes a thin interval of Wabiskaw Member glauconitic sands at the top (see text for discussion). The projection of Wabiskaw datum is an attempt to approximate a time surface equivalent to the Wabiskaw datum in the east. Towards the west, the Grand Rapids Formation sandstone undergoes a facies change to Clearwater Formation shale.


Rg 10
Rg 9
Rg 8
Rg 7
Rg 6
Rg 5
Rg 4
Rg 3
Rg 2
Rg 1
6-26-93-3W4
5-15-91-1W4
4-20-92-6W4
4-13-92-8W4
Grand Rapids Formation
/lineable Area
Athabasca River
Clearwater Formation
2-10-92-9W4
Wabiskaw Datum
10-12-92-10W4
'-92-10W4
McMurray Formation
(McMurray/Wabiskaw)
500
450
400
350
300
250
200
Elevation Above Sea Level (metres)

Trapping mechanism

The trapping mechanisms in the Athabasca deposit are not fully understood, but both stratigraphic and structural elements are involved. The regional dip of the formations to the west, combined with salt collapse in the east, resulted in a structural dome in the Athabasca area (Vigrass, 1968; Jardine, 1974); Clearwater shales provide the cap rock for the reservoir. Much of the reserves in the deposit, however, lie east of this anticlinal feature. MacCallum (1977) suggests this is because the salt solution front has migrated to the west since Cretaceous time and that closure did exist at the time of oil migration. Vigrass (1968), on the other hand, shows that the domal feature has remained in the same position since Lower Devonian (Elk Point Formation) time. If closure did not occur, other trapping mechanisms must have been involved. Degradation of the oil during migration may have rendered it immobile and, perhaps, created a bitumen plug as the up-dip seal (Mossop, 1980).

Because of a poor understanding of the trapping mechanism and a lack of well control east of R 6 W4, the eastern limit of the deposit is poorly defined. Bitumen is certainly found farther east than the present deposit limit. In one well in Tp 98, R 3 (Shell Athabasca East 98-3 #2), over 30 m of rich oil sand was recovered in core. Further drilling is necessary to define the extent of bitumen resources in this area and their continuity with the rest of the deposit.

Previous work

M. Carrigy of the Alberta Research Council did most of the early work on the geology of the Athabasca deposit including general works on stratigraphy and lithology (Carrigy, 1959a), detailed studies of lithology (Carrigy, 1959b, 1962, 1963a, 1963b, 1966) and studies on sedimentary structures and paleoenvironments (Carrigy, 1963c, 1967, 1971).

Stewart (1963) mapped the pre-Cretaceous unconformity, top of McMurray and distribution of reserves. He later developed a facies model for the McMurray Formation (Stewart, 1981; Stewart and MacCallum, 1978). Facies studies on smaller areas of the deposit have been done by Flach (1977), James (1977), James and Oliver (1978), Nelson and Glaister (1978) and Knight *et al.* (1981). The areas considered in the last two studies are south of the present study area. Mossop (1980) discusses the importance of facies as a control on bitumen saturation and Pemberton *et al.* (1982) discuss the trace fossil assemblages in the McMurray Formation.

Mossop and Flach (1983) outline a facies model for channel deposition in the McMurray Formation based on the outcrops in the valley of the Athabasca River and its tributaries. Flach and Mossop (in press) and the present report expand this model and carry it into the subsurface.

Outtrim and Evans (1978) estimate the reserves of the deposit and evaluate their recovery potential. The Alberta Energy Resources Conservation Board regularly publishes updated estimates of reserves.

Hackbarth and Nastasa (1979) studied the hydrogeology of the Athabasca oil sands area. In addition to hydrogeological data, their report contains structure maps of several formations over most of the deposit.

The K.A. Clark volume (Carrigy, 1963d) and *Guide to the Athabasca Oil Sands Area* (Carrigy and Kramers, 1973) are two collections of papers on the Athabasca oil

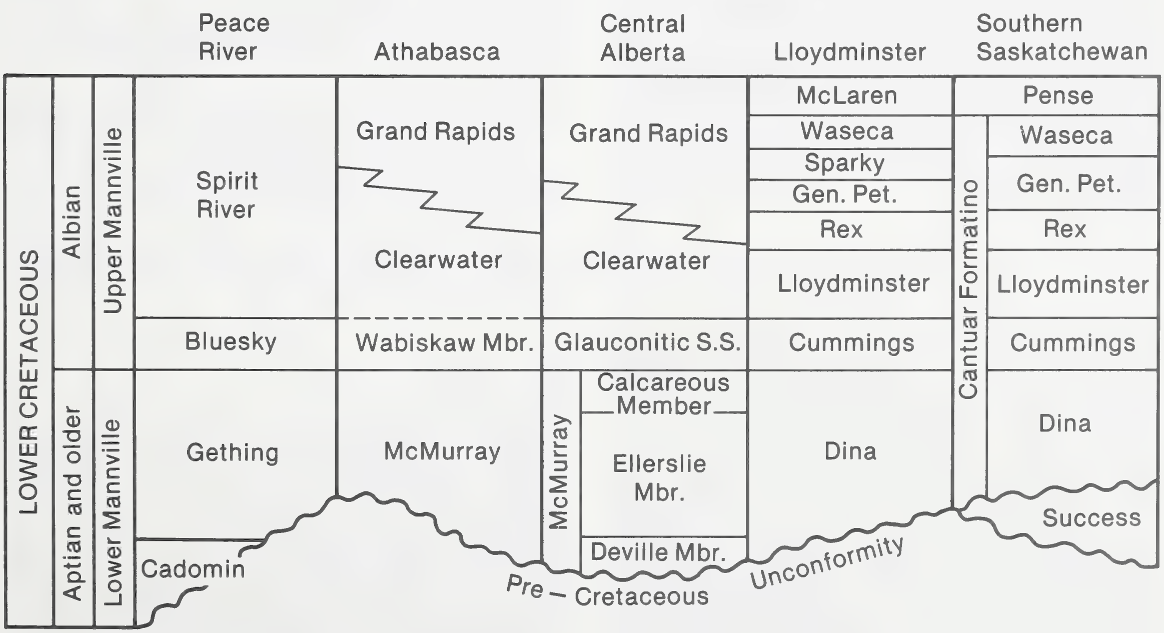


Figure 3. Correlation chart of Lower Cretaceous strata.

sands deposit. Two recent conference proceedings that provide a background to oil sands in general, from regional geology to in situ pilot testing, are Redford and Winestock (1978), and Meyer and Steele (1979).

Summary papers on in situ recovery processes in oil sands include Towson (1977) and Burger (1978). Redford (in press) provides a valuable review and summary of in situ pilot testing in the Athabasca deposit.

Purpose of the study

The first objective of the study was to map the geology and reservoir characteristics of the McMurray Formation and Wabiskaw Member of the Clearwater Formation in the northern part of the Athabasca deposit, from Tp 90 to 104, R 6 to 20 W4.

The second objective was to develop an understanding of the depositional environments of the McMurray-Wabiskaw interval, and to develop a general facies model with some predictive capability for future oil sands developments in the Athabasca deposit.

The limited control used in the maps precludes their use in detailed site studies. The report is intended, instead, to provide a regional framework for more detailed geological studies and to furnish a regional inventory of deposit characteristics, so the applicability of various recovery processes over the deposit as a whole can be assessed.

Methods of investigation

In order to map the structures of the pre-Cretaceous unconformity and top of the Wabiskaw Member and to make an isopach of the McMurray-Wabiskaw interval, a control of up to one well per section was used where available (a total of 1215 wells).

To map facies and reservoir characteristics, four wells were chosen per township (336 total) on the basis of log quality, availability of core, presence of the Wabiskaw marker (to allow stratigraphic analysis) and spatial distribution. Through the study of geophysical logs, core, and oil saturation analyses (where available), a log was constructed for each well indicating lithology and oil saturation throughout the McMurray-Wabiskaw interval (see *Application to in situ recovery*).

From the lithology/saturation logs, maps were generated to show (1) facies trends, in the form of sand thickness maps for the McMurray-Wabiskaw interval as a whole and for 20 m thick slices through the interval, and, (2) reservoir characteristics, including thickness of pay, uninterrupted pay, underlying water sand, and overburden. The maps were computer contoured.

Core was available for 125 of the 336 control wells. From this information, along with outcrop work done previously (Flach, 1977; Mossop and Flach, 1983), a depositional model for the formation was formulated (see *Depositional environments and facies*). Simplified representations of the facies sequences for many of the cored wells are shown in the cross sections of figures 4 and 5 (in pocket).

Computer contouring

The maps in this report were contoured by computer, using the Surface II Graphics System developed at the Kansas Geological Survey; most were drafted for publication with only minor cosmetic changes. Computer contouring provides an objective assessment of regional trends irrespective of differing geological interpretations.

The Surface II mapping program mathematically determines the placement of contour lines by making a rectangular grid of values (calculated from the scattered well control), through which the contours are threaded. For these maps, the grid has been calculated by first making a pass to determine a first order trend surface at each well control point, based on surrounding wells. These trends were then projected to the nearby grid nodes. The resulting value at each grid node is a distance-weighted average of the projected values. This projection of trends commonly results in contours of a higher or lower value than any of the data points, representing the extrapolated positon of the high or low on the basis of existing trends. This is in contrast to a simple distance-weighted average of the actual well control value, in which case the highest contour on the map would exactly correspond to the highest data point value.

In areas of dense control, such as on the maps of the pre-Cretaceous unconformity, McMurray Formation top and McMurray Formation isopach, all points may not be precisely honored. Although this approach may not be suitable for a detailed lease evaluation, in a regional study such as this, some averaging can be tolerated.

Sampson (1978) provides a complete discussion of the Surface II mapping program.

Structure and paleotopography

McMurray Formation structure

Over the eastern portion of the study area, a widespread, consistent resistivity log pattern represents the first regionally correlatable marine shale above the unconformity (Wabiskaw datum, figure 2). Immediately below this datum is the glauconitic Wabiskaw Member of the Clearwater Formation. Because of its widespread, uniform nature and its constant position relative to overlying markers, the base of this marine shale marker is thought to represent what was a nearly horizontal surface at the time of deposition. Since the top of the McMurray Formation itself cannot be consistently picked from well to well, this "Wabiskaw datum," lying a few metres above, is used as a close approximation. West of approximately R 13 W4, the distinctive log character of the datum is lost and thick Wabiskaw sands are developed above (figure 2). In these areas, the stratigraphic position of the datum is approximated by measuring down a fixed distance from up-hole picks ("projection of Wabiskaw datum" in

figure 2), so the map of the top of the McMurray Formation should approximately represent a time surface.

Assuming the datum was near horizontal at the time of deposition, the structure on this surface (McMurray Formation Structure: map 1, in pocket) reflects the structural movement that has occurred since the end of McMurray time. Major influences include:

- Regional tilting to the northwest. South of the present study area, regional dip is distinctly to the southwest but north of approximately Tp 90, regional dip is to the northwest (Stewart, 1963, figure 5; Vigrass, 1968, figure 7; and map 1 of this report). This change in regional structure is probably due to the effects of the Peace River Arch, a structural high running east-west through the Fort McMurray area (Stelck, 1975).
- Collapse features related to the solution of underlying evaporites. North-south trending lows through the central part of the study area are a result of post-McMurray leaching of salts of the Middle Devonian Elk Point Formation and the collapse of the overlying Beaverhill Lake Formation. The most pronounced of these structural lows is the Bitumount basin in Tp 96, R 10 to 11 W4. This structural control on drainage makes the present Athabasca River follow a course very similar to that of rivers in McMurray time. Saline springs in the area indicate that salt solution is occurring to the present day (Carrigy, 1959a).

Unconformity structure and McMurray Formation isopach

The McMurray Formation was deposited in a north-south trending depression on the pre-Cretaceous erosional surface. This depression was initiated by solution removal of Middle Devonian evaporites and the consequent collapse of overlying formations. A fluvial drainage system occupied the depression in early Cretaceous time, sculpting the exposed limestone into a landscape of highly variable relief. Stewart (1963) notes the importance of this relief in controlling the distribution of reserves in the Athabasca deposit. The bulk of the reserves in the deposit are contained in channel sands of the lower and middle members of the McMurray Formation; the paleotopography to a large extent controlled the locus of the channels that deposited what are now the richest oil sand bodies. Mapping the paleotopography is thus a critical step toward understanding the regional distribution of facies and reserves.

Because the Wabiskaw datum is believed to represent what was an almost horizontal time surface, an isopach of the McMurray-Wabiskaw interval closely approximates the pre-Cretaceous paleotopography (map 2, in pocket). The isopach represents a "mold" of the unconformity surface, with thins representing highs (red, orange on map 2) and thicks representing lows (green, blue). Unfortunately, the datum has been eroded over a significant part of the study area, around the valley of the Athabasca River. The present structure on the unconformity surface (map 3, in pocket), however, maintains the basic elements of the pre-Cretaceous paleotopography and has been used to estimate isopach values where the datum is missing (dashed contours on map 2). The major differences between the present Devonian surface (map 3) and the surface as it was in pre-Cretaceous time (represented by map 2) result from post-McMurray regional tilting, which has caused higher structure in the east and lower in the northwest; and from collapse (due to removal of underlying evaporites), such that valleys which existed in pre-Cretaceous time along the edge of salt leaching, are now deeper (for example, the valley from Tp 94, R 12 W4 to Tp 93, R 11 W4).

The dominant feature of the pre-Cretaceous paleotopography is the large basin centered around Tp 96, R 9 to 12 W4, and the associated valleys toward the south. Carving by early Cretaceous and pre-Cretaceous streams in this area created topography with considerable relief. The more gentle gradients in the west are real, not just a result of less well control. The ancient rivers followed the structural low in the east and had much less effect in the area west of a line from Tp 91, R 10 W4 to Tp 96, R 13 W4.

Depositional environments and facies

Depositional setting

Isopachs of the McMurray Formation, representing the paleotopography, indicate that in earliest McMurray time, drainage was to the north and south from a divide centered at Tp 92, R 8 to 10 W4 (Stewart, 1963, figure 3; Carrigy, 1971, figures 2, 6). This paleotopographic high is the eastern extension of the Peace River Arch, which Stelck (1975) shows running through the Fort McMurray area. Christopher (1980) suggests that a Neocomian uplift of the Precambrian Shield, probably corresponding to this high stand of the Peace River Arch, resulted in drainage from the Shield to the south in Saskatchewan and deposition of the Success Formation. In the Athabasca oil sands area, the lower member of the McMurray Formation may contain some corresponding remnants of pre-Aptian age. Carrigy (1966) reports several occurrences of coarse-grained sands cemented with quartz, goethite or kaolinite to which he assigns a pre-McMurray age. Exposures of the lower member of the formation on the Steepbank River include coarse-grained, kaolinitic, quartzose sands with beds of siderite nodule conglomerates bearing a strong resemblance to Success Formation sediment described by Christopher (1980). Sandstone pebbles cemented with iron carbonate present in the conglomerates indicate erosion of yet older lithified sediments and suggest a complex pre-Aptian history.

In late Neocomian and early Aptian time, drainage of

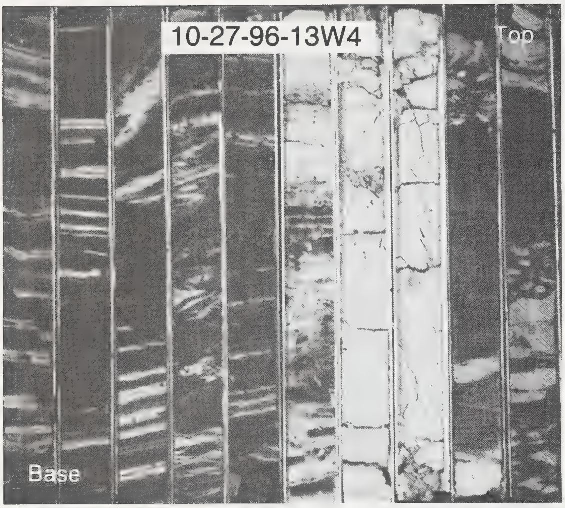


Figure 6. Top of upward-fining lower member channel, 10-27-96-13W4 (see log of well on cross section D-D', Fig. 4, in pocket). Oil sand (black) with thin shale partings (light) grades upward to mudstone containing root structures and to coal at top of lower member. This is overlain by a middle member sand containing abundant shale clasts.

the continental interior of western North America was probably to the Pacific Ocean, through a northwestward flow to the Hazelton area of British Columbia (Williams and Stelck, 1975). Williams and Stelck (1975) speculate that, in middle Aptian time, this drainage was blocked by the rising Ominica-Nelson batholith and that the rivers with headwaters from the southern United States began to flow north, to the Athabasca oil sands area. McLean (1977) illustrates this drainage system, as does Christopher (1980) on the basis of detailed mapping in Saskatchewan. If such a rerouting of drainage did occur, it would probably have resulted in widespread flooding in the interior of western North America and in the local establishment of lakes and lacustrine deltas as the new drainage pattern was being developed. Williams and Stelck (1975) note the widespread occurrence of fluvial/lacustrine deposits of late Aptian age in the western interior, as well as the lack of appreciable amounts of earlier Aptian sediments. The bulk of the McMurray Formation, including all of the middle and upper members and most of the lower member, is probably of Aptian age (C. Singh, pers. comm.), the sediment being supplied by a northwestward flowing fluvial system (Carrigy, 1963c, 1967).

In Saskatchewan, this northward-flowing river system eroded into the underlying Success Formation; the deposited sediments comprise the Dina Member of the Cantuar Formation (Christopher, 1980) (figure 3). Determining how much of the lower member of the McMurray Formation in the Athabasca area is "Success" equivalent as opposed to "Dina" is, however, beyond the scope of this study.

During Aptian time, a major eustatic rise in sea level (Williams and Stelck, 1975) and an eventual transgression of the Clearwater Sea from north to south also occurred. The interplay between rising sea level and what was probably a very significant northward flowing fluvial system resulted in the deposition of the bulk of the McMurray Formation. At the end of McMurray time, the entire area was transgressed.

Facies analysis

Geologists working on the Athabasca deposit are fortunate that the McMurray Formation crops out in cliff exposures along the Athabasca River and its tributaries near Fort McMurray and is exposed in the surface mining pits of Suncor and Syncrude. Outcrop work, because it affords the opportunity for documenting paleocurrent data and lateral facies relationships, has profoundly increased our understanding of McMurray Formation facies and allows us to extrapolate into the subsurface with some confidence.

Outcrop work alone, however, provides an incomplete picture of the sedimentology and depositional history of the formation. This is due mainly to the following factors:

1. Fine-grained facies, which contain important evidence regarding depositional environment, are generally not exposed at outcrop because of their recessive character.
2. The lower member of the formation is poorly represented in outcrop exposures because it typically lies below present-day river levels.
3. Outcrops of the McMurray Formation are generally confined to the central portion of the deposit, along the course of the Athabasca River and its tributaries, whereas facies characteristics change considerably over the breadth of the deposit.

A thorough understanding of the formation, therefore, requires subsurface study.

Cross sections A-A′ to H-H′ (figures 4, 5, in pocket), referred to in the following discussion of the facies sequences found in the subsurface, are hung on the Wabiskaw datum. In the western part of the study area, where the datum is obscured, its stratigraphic position is estimated from up-hole picks (figure 2 and cross sections E-E′ and F-F′, figure 5). No cross sections were constructed in the mineable area of the deposit because the datum in this area has been eroded.

Members of the formation

The division of the McMurray Formation into the lower, middle and upper members, as defined in the outcrop area (Carrigy, 1959a), is a useful breakdown of the formation over a large part of the study area. In most of the cross sections, the members have been differentiated. In places, however, the division is difficult to apply or is inappropriate, generally because of the gradational nature of the members.

In the interpretations of depositional history that follow, reference is made to lower, middle and upper member "time." This temporal reference to members is valid in a general sense because of the very low gradient of a coastal plain system as is the model for the McMurray Formation. The Amazon River, for instance, in its lower 1440 km has an average gradient of less than 0.03 m/km (2 in per mi). If the system which

deposited the McMurray Formation had had a similar gradient, as is believed to have been the case, the relief over a distance equal to the width of the present study area (145 km, 90 mi) would have been less than 4.5 m (15 ft). Within this setting, local relief was probably also very low. On the Mississippi delta plain, for instance, levees are a maximum of 1.5 m (5 ft) high and lakes and interdistributary bays are less than 4 m (12 ft) deep (Coleman and Gagliano, 1965). Over the present study area, therefore, sediments at the same stratigraphic level are assumed to have been deposited more or less synchronously. Exceptions to this general rule are caused by the effects of compaction — shale (mud) sequences having been compressed more than laterally equivalent sands; and by the presence of channels that cut deeply into previously deposited sediment, so that the channel deposits lie adjacent to what may be much older strata. Exceptions to the model of deposition in very shallow water are indicated by the presence of some middle member upward-coarsening sequences, 15 to 20 m thick, in the north and west of the study area (1-22-100-13W4 and 16-34-99-13W4 in cross section G-G′, figure 5) and thick marine upward-coarsening units of the upper member (for example, 8-33-98-12W4, 8-15-99-12W4, cross section G-G′, figure 5). Upward-coarsening sequences of this thickness, which are apparently genetic units, suggest deposition in water of at least that depth.

Lower member

Stratigraphy

The lower member of the McMurray Formation fills lows on the unconformity surface and is generally present where the thickness of the formation is greater than about 60 m. Thick sections are thus confined to the center of the study area (cross sections A-A′, B-B′, C-C′ and D-D′, figure 4). In the western part of the study area, localized occurrences of lower member sediment are found at higher stratigraphic levels (cross section F-F′, figure 5).

Maximum thickness of the member occurs in the Bitumount basin where, in 16-27-96-11W4, the lower member is composed of 75 m of water-bearing sand overlain by 15 m of shale and coal. The entire formation at this location is 160 m (525 ft) thick.

The top of the lower member commonly coincides with the highest points on the surrounding limestone paleotopography (cross sections B-B′ and D-D′, figure 4).

Lithology

Fine-grained facies of the lower member are commonly blocky mudstones, in contrast to the uniform light gray, more fissile shales of the middle member. Dark gray, waxy, carbonaceous mudstones and thin coals, often containing root structures, are common, especially near the top of the member (figures 6, 7 and cross sections A-A′, B-B′, C-C′, and D-D′, figure 4). Carrigy (1959, p.36) notes the presence of a dark gray carbonaceous shale at the top of the member. Ironstone nodules and contorted bedding are common in the fine-grained facies of the lower member. The grain size of sands in the lower member is highly variable but, on average, is coarser than that of the middle and upper members. Medium to coarse-grained sands are common, with local conglomerates composed of pebbles up to one or two centimetres in diameter. Conglomerates coarser than this are rare. Some conglomerates exposed at outcrop on the lower Steepbank River (figure 1), with cobbles and boulders a decimetre and larger in size, are interpreted as part of an earlier (possibly Neocomian) event, unrelated to the bulk of McMurray sedimentation. The coarsest sediment is almost always found near the base of the formation and the member as a whole has an upward-fining tendency, as does the formation. Sand bodies of the lower member commonly consist of small upward-fining sequences, 5 to 10 m thick (cross section D-D′, figure 4), which are stacked in places (especially in narrow valleys on the unconformity surface) to form much thicker units.

Water-bearing sands are very common at the base of the lower member, below the regional oil/water contact (figure 7 and cross sections A-A′, C-C′ and D-D′, figure 4). These sands are commonly argillaceous; in places

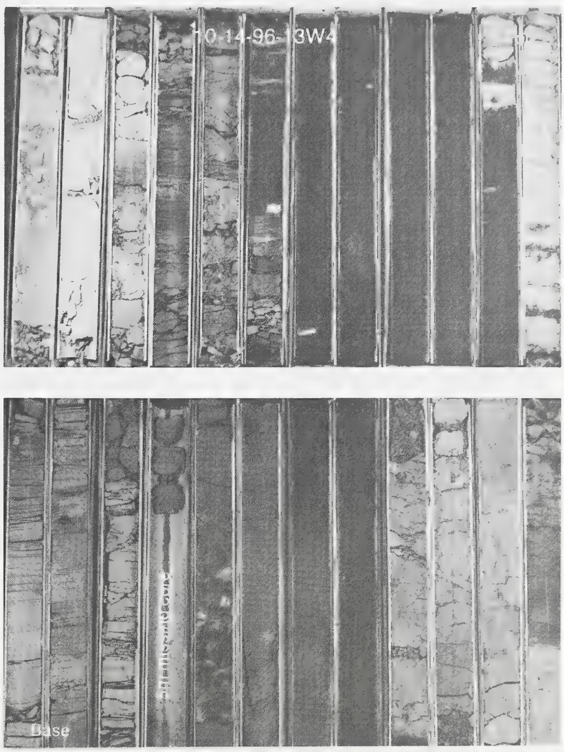


Figure 7. Lower member to middle member, 10-14-96-13W4 (see log of well on cross section C-C', figure 4, in pocket). Thin bedded Devonian limestone at base is overlain by water sand which grades upwards into rich oil sand (black). The sand fines upward from medium to coarse-grained at the base to very fine to fine-grained at top. Above this lies mudstone containing root structures, and very carbonaceous shale. Overlying the carbonaceous interval is a richly oil saturated, upward-fining channel sand (medium to coarse at base, fine-grained at top). Core tube lengths 0.76 m. Core diameter 7.6 cm.

the original porosity has been completely occluded by kaolinite.

Burrowing is rare in the lower member and palynology indicates dominantly continental conditions with rare brackish indications. The strongest indication of marine influence was found in 5-33-95-11W4 (cross section C-C′, figure 4), approximately 85 m below the Wabiskaw datum. At this level, bioturbation and a proliferation of the acritarchs *Micrhystridium* and *Veryhachium* indicate brackish conditions (C. Singh, pers. comm.). Wave ripples, generally found only in the upper member of the formation, are also present in this zone.

Interpretation

On the basis of the abundance of well-defined upward-fining sequences, the presence of coals and rooted zones, the general lack of burrowing and palynological evidence indicating a basically fresh water origin for the associated shales, the depositional environment of the lower member is interpreted as dominantly fluvial. Rare brackish influences, however, suggest a coastal setting with some invasion of salt water.

River morphology types ranging from braided to meandering are probably represented in the lower member, with meandering river types apparently dominant. Upward-fining sequences a few metres thick, common in the lower member, are characteristic of point bar lateral accretion in meandering systems (Allen, 1970; Bernard *et al.*, 1970). These sequences are also found in braided stream deposits as a result of point bar accretion and vertical aggradation (Miall, 1977), but are probably not as common nor as well developed. A typical braided river deposit is more likely composed of randomly interbedded, cross-bedded and rippled units with no systematic upward change in grain size or size of cross-bedding (Collinson, 1978, p.29). The high proportion of fine-grained interchannel sediment in some areas and the abundance of coals and carbonaceous shales (5-33-95-11W4, cross section C-C′, figure 4) also favor a meandering stream model. Little fine-grained sediment is normally preserved in braided stream environments, since the channels are wide and shallow and tend to sweep the entire floodplain. In meandering streams, on the other hand, channels are typically narrow and deep, migrate relatively slowly and are restricted to a relatively narrow meander belt by their own abandoned channel clay plugs. The presence of coal indicates relatively stable conditions in the off-channel areas, especially near the end of McMurray time.

In meandering streams, the thickness of an upward-fining sequence resulting from point bar deposition approximates the depth of the paleochannel. Paleochannels represented by the upward-fining sequences thus appear to range from 5 m or less in depth (for example, 5-20-96-11W4, cross section D-D′, figure 4) to over 15 m (base of 5-33-95-11W4, cross section C-C′, figure 4); averaging about 7 m.

The lower member shown in cross section D-D′ (figure 4) shows attributes of both braided and meandering systems. Well-defined small upward-fining sequences present in some wells, capped by shale, suggest a meandering system (5-20-96-11W4), whereas thick sections of sand with no fines (9-33-96-11W4) are more typical of braided stream deposits.

The relative lack of in-channel fines in the lower member, compared to the overlying middle member deposits, suggests that less suspended load sediment was carried by these rivers. The lack of fines results in thick, continuous reservoirs with few shale breaks where channel sands are stacked.

Middle member

Stratigraphy

The middle member of the McMurray Formation generally occupies an interval from approximately 20 m below the top of Wabiskaw datum to the top of the lower member, about 60 m below the datum. The contact with the lower member can be sharp and distinct or gradational. Since the characteristics of the fine-grained facies form the main basis for distinguishing between the two members, problems arise in areas where only sand is present. In places, middle member channels erode deeply into lower member sediment (for example, 10-3-97-12W4, cross section D-D′, figure 4).

The top of the middle member is generally gradational with the upper member; in places, the two represent a channel to off-channel facies change (see upper member).

Lithology

Fine-grained facies of the middle member consist of light gray shale and interlaminated to interbedded sand and shale, typically burrowed and commonly completely bioturbated. Current ripples are the most common sedimentary structure in the thin sand interbeds. Frequently, thick uniform sequences (up to 30 m of shale or methodically interbedded sand and shale) compose the entire middle member (cross sections B-B′, and D-D′, figure 4). Coals and rooted zones are notably absent in the middle member throughout the study area.

Sands in the middle member are generally very fine to fine grained, except in the east central part of the study area (Tp 94 to 97, R 6 to 8 W4) where coarse sands are common. Shale clast breccias within sands are common throughout the study area. Sand bodies are most commonly upward-fining sequences, generally much thicker than those of the lower member. The sequences average 20 to 25 m in thickness and are up to 35 m thick in places (cross sections A-A′ to D-D′, figure 4). The upward-fining character of a sequence is usually more a result of an upward increase in the number and thickness of shale breaks than of a decrease in sand grain size.

A typical middle member upward-fining sequence (figure 8) consists of a sharp base, overlain by 10 to 15 m of richly oil-saturated cross-bedded sands, commonly containing medium to coarse sand or shale clast breccias. Thin shale breaks are present higher in the sequence, increasing in abundance upward. In some cases, shale partings are present down to the base of

the sequence. Current ripples are the dominant primary sedimentary structure in the upper part of the sequence. Burrowing increases upward and upper parts of the sequence are commonly completely bioturbated. Upward-fining sequences in the outlying areas of the deposit, to the west and north, tend to be thinner (cross section F-F′, figure 5).

In places, especially the east-central part of the study area, thick sand sequences with abundant shale clasts and little or no upward-fining tendency are common (16-33-94-7W4, cross section B-B′ and 10-27-96-13W4, cross section D-D′, figure 4).

Upward-coarsening sequences in the middle member are virtually absent throughout most of the study area, except in the north and west. There, these units are 10 to 15 m thick and consist of interlaminated to interbedded sand and shale, with the amount of sand increasing upward (figure 9 and cross section G-G′, figure 5).

Palynomorphs in middle member shales indicate deposition in fresh to slightly brackish water. The dinoflagellates *Muderongia* sp. and *Palaeoperidinium cretaceum* Pocock, 1962 are common throughout the study area.

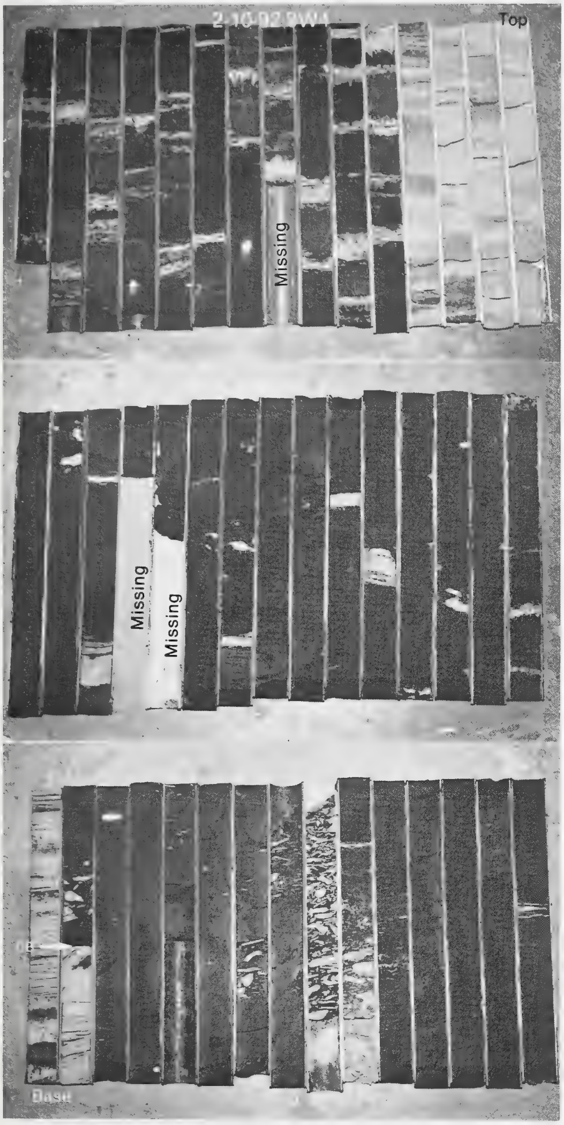


Figure 8. Upward-fining middle member channel deposit, 2-10-92-9W4. A sharp erosional base is overlain by richly oil-saturated fine-grained sand (black) with zones of shale intraclasts. Thin shale breaks (light in color) increase in abundance upwards and the sands become more argillaceous and less heavily oil saturated. At the top, the sequence grades to overbank sandy shale. Core tube lengths 0.76 m, core diameter 7.6 cm. See log of well on cross section A-A′ (figure 4, in pocket).

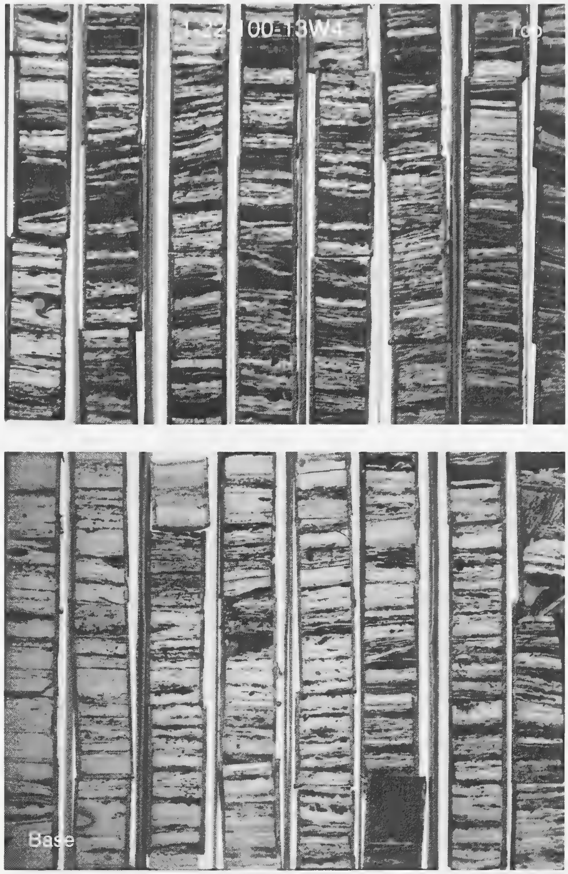


Figure 9. Middle member upward-coarsening sequence in northern part of study area, 1-22-100-13W4 (see log of well on cross section G-G′, figure 5 in pocket). The sequence shown appears to be a continuous genetic unit, suggesting deposition in water depths of at least 12 m. Such upward-coarsening sequences are rare except in the north and west of the study area. Core tube lengths 0.76 m, diameter 7.6 cm.

Interpretation

On the basis of detailed outcrop work, thick upward-fining sequences of the middle member are interpreted as the lateral accretion deposits of very deep (20 to 30 m) sinuous channels (Mossop and Flach, 1983). Outcrop exposures of the middle member are in many places characterized by very large scale (10 to 20 m thick) sets of epsilon cross-strata (figures 10, 11), consisting of decimetre to metre thick sand beds separated by thinner partings of silt and shale (figure 12) and lying at a depositional dip averaging 12 degrees. The individual sand beds are generally current rippled throughout and vertical lined burrows *(Skolithus)* are common (figure 13), becoming more abundant upsection. The inclined epsilon cross-strata generally overlie thicker bedded, usually trough cross-bedded, clean, fine-grained sands (figure 14), which sometimes contain angular clasts of shale (figure 15). The trough cross-sets vary from 50 cm to 1.5 m in thickness.

The following characteristics of the sequence indicate a channel origin:

1. a scour base
2. an upward-fining of sand grain size and an upward increase in the number and thickness of shale partings
3. an upward decrease in the scale of cross-bedding from large-scale trough cross-beds (sets up to 1.5 m thick) at the base to current ripples at the top
4. continuity of bedding from the epsilon cross-strata down into the trough cross-bedded sands, indicating that deposition of the two facies was synchronous, and
5. unidirectional paleocurrent directions, parallel to the strike of the epsilon cross-strata and slightly up the dip (figure 16 b).

See Mossop and Flach (1983) for details.

The trough cross-bedded facies represent sedimentation by large bed forms (dunes) deep in the channel; the epsilon cross-strata resulted from lateral accretion of the point bar of the same channel. The sand beds in

Figure 10. Outcrop of McMurray Formation, lower Steepbank River. Light colored Devonian limestone at base is overlain by thick-bedded, trough cross-bedded sands, in turn overlain by dipping epsilon cross-strata; horizontally bedded units at top comprise the upper member and are overlain by Clearwater Formation shales (recessive, tree-covered).

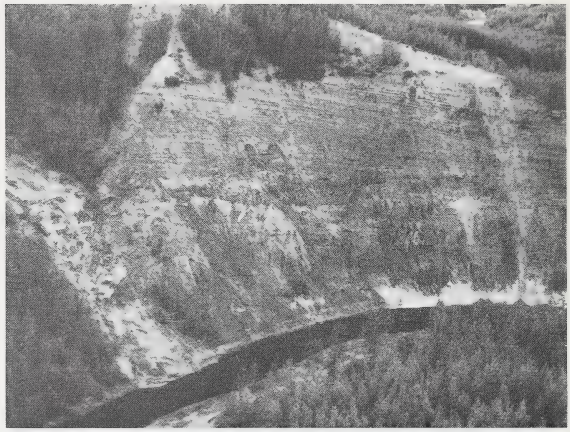


Figure 11. Outcrop of McMurray Formation, lower Steepbank River. Light colored Devonian limestone at bottom right is overlain by interlaminated shale, silt, and very fine sand. Above this is an erosionally-based, fine-grained, trough cross-bedded sand unit which grades upwards into the sand/shale couplets of epsilon cross-strata. The top of the formation is missing due to Pleistocene erosion.

Figure 12. Bedding within epsilon cross-strata consists of decimetre to metre thick beds of very fine to fine-grained, current rippled sand (dark gray, oil saturated), separated by thinner (1 to 10 cm) partings of shale (light gray) and interlaminated sand and shale.

the epsilon cross-strata are interpreted as having been deposited during flood stage, with the shale drapes resulting from suspended load fall-out during times of low discharge. Shale clast breccias near the base of the channel resulted from the incorporation of fine-grained blocks introduced by cutbank caving.

On the cross sections (figures 4, 5), what appear to be fairly well defined upward-fining channel sequences have been marked. Some of these sequences may represent stacked channel deposits, but the abundance of distinct upward-fining units, 20 to 30 m thick, suggests that most are single genetic units, similar to those seen in outcrop.

Thick sands in the middle member that do not display an upward-fining character probably represent either stacked channel sands, representing shallower streams, possibly of a more braided character; or a large channel in which the vertical section shown is through a part of the point bar where an upward-fining sequence is not well developed: depending on where the section is taken, the grain size trend in a point bar deposit may be upward-fining, constant or upward-coarsening (Jackson, 1976). Where thick sands in the middle member do not display an upward-fining character, more well control from the immediate area would be necessary to determine the genesis of the sand body. This genesis is *not* just an academic question: the differences in sand body characteristics and geometry between stacked channel sands and single large channels may have profound implications for an in situ recovery operation.

Flach and Mossop (in press) discuss the depositional environment and degree of marine influence in the middle member. They suggest that the unimodal paleocurrent pattern over the entire outcrop area of the Athabasca deposit (figure 16a) indicates processes of channel formation that were dominantly fluvial, rather than dominantly tidal as Stewart (1981) suggests. On a regional scale, one would expect to see a bimodal pattern if tidal processes were dominant (Clifton, 1982). On the other hand, the abundant burrowing within the epsilon cross-strata and overbank deposits (Pemberton *et al.*, 1982) and the presence of rare brackish water dinoflagellates suggests some saline influence. Most workers, recognizing both the fluvial and marine aspects of the middle member channels, use the terms "distributary" and "estuarine" to describe the depositional environment (Nelson and Glaister, 1978; Knight *et al.*, 1981). Flach and Mossop (in press) argue that the term "estuarine" is somewhat misleading in that it implies that tidal processes dominated the pattern of sedimentation (for example, Clifton, 1982, p.179), which does not appear to be the case; it also implies a "funnel-shaped opening of a river in the sea" (Reineck and Singh, 1980, p.315), whereas the channel patterns were most likely highly meandering, with relatively narrow channel widths (see "paleochannel reconstruction").

The characteristics of these channel deposits are consistent with what one would expect from a large fluvial system aggrading rapidly in response to rising sea level. Rising sea level decreases the gradient of the system, which in turn results in more highly sinuous channel patterns, very deep channels with low width/depth ratios, and a fine-grained load and high suspended load (see Flach and Mossop, in press). During low stage, the channels were apparently subject to invasion by marine waters.

The thick shale sequences of the middle member are interpreted as having been deposited in shallow, long-standing lakes and brackish bays that existed contemporaneously with the channels. This interpretation is suggested by the fact that the tops of individual upward-fining channel deposits (representing former elevations of the floodplain) occur at all stratigraphic levels in the formation, indicating a gradual up-building of the floodplain surface rather than progradation into a deep body of water. The absence of coal and rooted zones in the middle member is interpreted to be a result of very rapid aggradation due to sea level rise, and widespread subaqueous conditions in the interchannel areas. Both high flood frequency and abnormally thick overbank sediments are a result of rapid aggradation due to sea level rise (McCave, 1969). The amount of burrowing and

Figure 13. Abundant vertical to inclined, lined burrows within the epsilon cross-strata, probably representing the dwelling burrows of suspension-feeding polychaete worms.

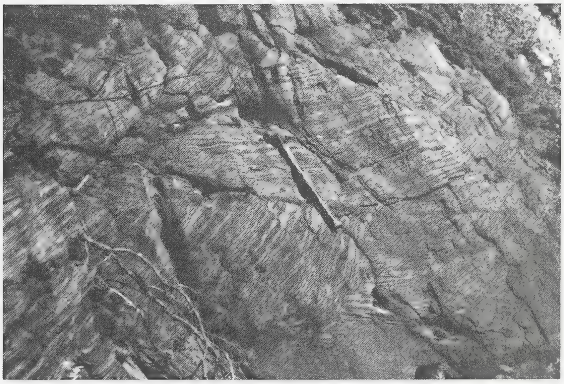


Figure 14. Trough cross-bedded sands underlying the dipping epsilon cross-strata.

Figure 15. Shale clast breccia within the trough cross-bedded sand facies.

the palynological evidence suggest some saline influence in many of the interchannel sediments of the middle McMurray, but the degree of marine influence is still open to question. Coleman (1966, p.166) and Coleman and Prior (1982, p.147) note that the polychaete worm, the organism thought responsible for the clay-walled burrows that predominate in the McMurray Formation, is the most common burrowing organism in lacustrine environments on the modern Mississippi delta plain. The dinoflagellates found in the middle member of the McMurray Formation (*Muderongia* sp. and *Palaeoperidinium cretaceum* Pocock, 1962) usually occur under very low saline conditions (C. Singh, pers. comm.).

The common rhythmic interbedding of shale and sand on a centimetre to decimetre scale in the interchannel areas is interpreted to be the result of flooding events of the river, although the sediments may have been deposited in brackish water environments. Wave ripples and bipolar current indications are absent in the middle member, suggesting that waves and tides had very little influence before upper member time.

Middle member upward-coarsening sequences 10 to 15 m thick in the west and north, as in 1-22-100-13W4, (cross section G-G′, figure 5; also figure 9) suggest progradation into water of at least that depth. Roots are found at the top of the middle member in this well, with open marine sediments a few metres above. This suggests the basin was filled to sea level during middle member time and colonized by vegetation before the marine transgression of upper member time. Whether these upward-coarsening units represent the splay deposits of rivers building a delta further to the north or the actual delta itself building into a brackish embayment flushed by river water is a matter for speculation. Of the cores examined in this study, only one suggests a distributary mouth bar, as opposed to an erosionally based channel (16-17-101-13W4, cross section G-G′, figure 5). In this core, the base of the sand appears gradational over tens of centimetres and wave ripples are apparently present near the base. The amount of shale interbeds decreases upward and the shales are dark colored in part, similar to the overlying marine shales. Bidirectional ripples are present near the top. The well occurs at the northern end of what is interpreted as a middle member channel system (see *Mapping of facies*, map 5C). Unfortunately, in the area north of Tp 98 and east of R 11 W4, constituting the axis of the depositional basin, the McMurray Formation is missing due to Pleistocene erosion.

Paleochannel reconstruction and sand body geometry
The richest oil sand bodies in the Athabasca deposit are generally the large, upward-fining channel deposits of the middle member. The presence of epsilon cross-strata in outcrop allows reconstruction of paleochannel dimensions which, in turn, provides some estimate of the size and geometry of individual oil sand bodies (Flach and Mossop, in press). If such reconstructions prove to be valid, they may have a significant impact on the design of future in situ recovery projects; thus, although the following calculations are prone to large error, it is nonetheless worthwhile to make a first attempt at estimating the paleochannel parameters.

The bankfull depth of the McMurray Formation paleochannels is approximated by the thickness of the upward-fining sequence, from the scour base below the trough cross-bedded sands to the top of the epsilon cross-strata. In a typical case (the outcrop pictured in figure 10), this thickness is 25 m, with epsilon cross-strata comprising the upper 15 m and trough cross-bedded sands the lower 10 m.

Assuming an average dip, through their respective thicknesses, of 10 degrees for the epsilon cross-beds and 4 degrees for the channel bottom beds (estimated from outcrop), the horizontal distance from the top of the point bar to the thalweg of the channel was approximately 230 m. Assuming some distance between the thalweg and the top of the cutbank, the total width of the

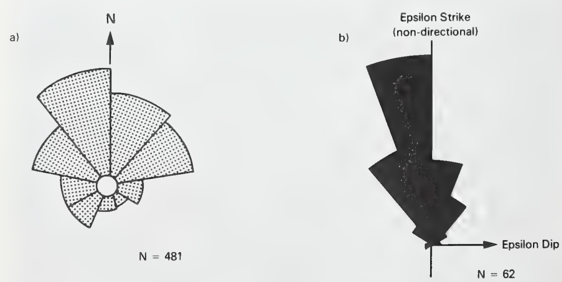


Figure 16. Unimodal paleocurrent directions over (a) the whole of the deposit (Carrigy, 1963) as well as (b) within individual channel deposits, (Mossop and Flach, 1983) suggests a dominance of fluvial processes of deposition and lack of significant tidal influence. In (b) the paleocurrent measurement is plotted relative to the strike of the associated epsilon cross-strata.

channel was probably on the order of 250 m (figure 17). Similar calculations for the outcrop shown in figure 11, an anomalously thick channel sequence, indicate a width of between 400 and 500 m for a channel 40 m deep. In both cases the width/depth ratio at a meander bend is approximately 10.

Having an estimate of channel width, one can then estimate the size of individual point bars. Leopold and Wolman (1960) show a consistent, almost linear, relationship between channel width (w), meander wavelength (L) and radius of curvature of meanders (r):

$L = 10.9w^{1.01}$

$L = 4.7r^{0.98}$

For a typical middle McMurray channel 25 m deep and 250 m across, therefore, one could expect meander wavelengths of approximately 3 km and radii of curvature averaging 700 m (figure 18).

At the type section of the McMurray Formation (Carrigy, 1959a), 5 km north of Fort McMurray on the Athabasca River, a single epsilon cross-set with constant dip to the north extends for about 2 km; this represents the minimum distance a point bar migrated before being cut off or abandoned. This is probably one of the largest point bars in the McMurray Formation. Other epsilon cross-sets, like those on the Steepbank River, appear more limited in lateral extent, although limited outcrop exposure hampers analysis.

Zwicky (1979) provides further evidence for individual sand body sizes of 1 to 2 km across. Zwicky applies the statistical concept of the variogram to the heavily drilled Alsands lease of the Athabasca deposit (figure 1). His data are interpreted here in light of the proposed point bar model of deposition. Epsilon cross-strata are present in the Alsands test pit and 20 to 30 m thick upward-fining sequences are common in the adjacent subsurface; this indicates the presence of meandering channel deposits similar to those at Suncor and Syncrude, in outcrop on the lower Steepbank River, and at the type section of the McMurray Formation.

A variogram shows the variation in a given parameter as a function of distance from other data points, with the "range" of the variogram showing the distance over which values appear statistically related. In the case of oil sand net pay data, the range should reflect the size of individual oil sand bodies. Where data density is sufficient, variograms can be constructed along different vectors and, thus, show sand body trends. For the central ore body of the Alsands lease, Zwicky found that net pay thickness has a much lower variability in a north-south direction than in an east-west direction, indicating north-south trending ore bodies. In an east-west direction, the "range" of the variogram, reflecting the width of individual oil sand bodies, is approximately 1200 m (Zwicky, 1979, figure 8). In a meandering stream model, this distance should represent either the size of individual point bars or the width of a meander belt, depending on the extent to which the meanders reworked the floodplain. A comparison of this figure to the previous calculations suggests that 1200 m represents an average point bar size.

Since sand body trends are not consistent over the whole lease, directional variograms are restricted to smaller areas. Non-directional data for the entire lease indicate a range, or average sand body size, of about 2.5 km (Zwicky, 1979, figure 5); this range represents a composite of measurements taken both on and off trend. One would expect directional variograms for these data to show range values along the sand body trend to be greater than the 2.5 km, and those at right angles to the trend (the width of the sand body) to be less. Assuming a meandering stream model, the difference between the two depends largely on the nature of the meandering. If the sand body represents a well-reworked meander belt, it will have a much higher "range" on trend than perpendicular to trend, indicating, a high length/width ratio. If, as a result of moderate point bar growth followed by abandonment, the sand body is "beaded," the on-trend and off-trend dimensions of the sand body may be subequal and represent the average size of isolated point bars.

The evidence at present suggests the point bar sand bodies of these large channels varied from several hundred metres to over 2 km across. The individual point bars, however, would generally be part of a larger belt of sand, representing the meander belt of the rivers. Leblanc (1972) estimates meander belt width as 15 to

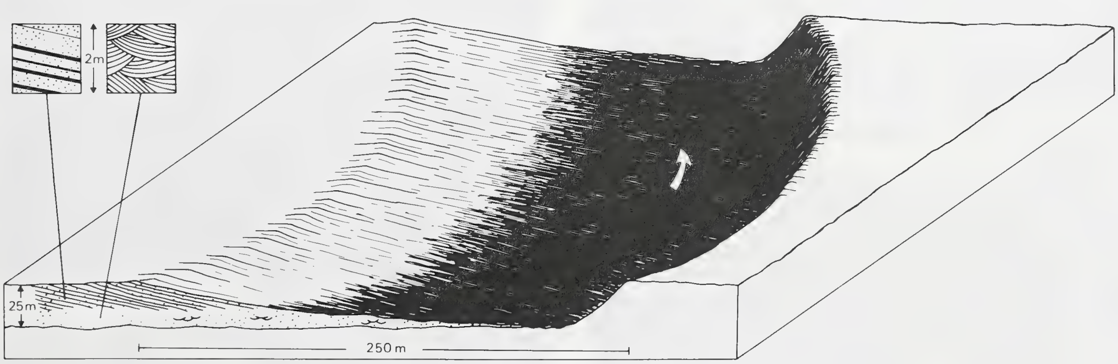


Figure 17. Reconstruction of paleochannel dimensions. For a typical middle member channel 25 m deep, outcrop geometry suggests a width on the order of 250 m. This is determined by extending the dip of the epsilon cross-strata (average 10 degrees) and channel bottom sands (4 degrees) through their respective thicknesses of 15 m and 10 m.

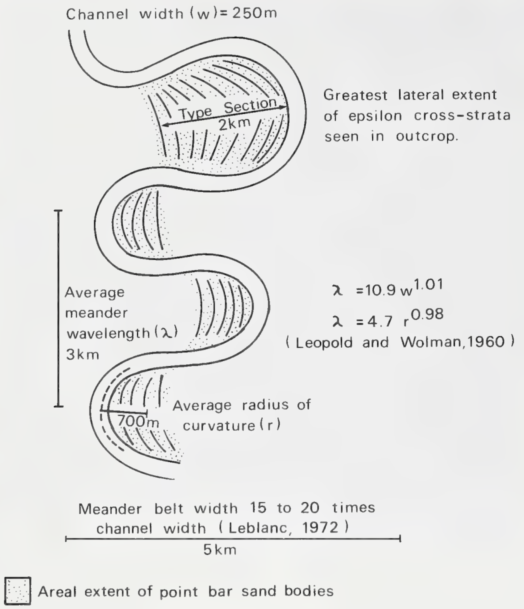


Figure 18. Schematic representation of point bar sand body size based on (1) the relationship of channel width to wave length and radius of curvature, and (2) the presence, in outcrop, of single sets of epsilon cross-strata up to 2 km in lateral extent.

20 times the channel width, or 4 to 5 km, for a typical 25 m deep (250 m wide) channel.

Upper member and Wabiskaw

Stratigraphy

In outcrop, the upper member of the McMurray Formation comprises the flat-lying beds overlying the dipping epsilon cross-strata of the middle member (figure 10). Over most of the study area, the upper member is 15 to 20 m thick. In some outcrops and drill holes, however, channel deposits of the middle member occur in a high stratigraphic position and the upper member is correspondingly much thinner (figure 19). Flach and Mossop (in press) suggest that in many areas the upper member represents the off-channel facies of large channels that existed late in McMurray time. This relationship is shown in figure 20. In these areas, the two members are, thus, gradational and represent a local facies change.

The upper member of the McMurray Formation is overlain by the Wabiskaw Member of the Clearwater Formation, where the latter is present. The Wabiskaw Member is a glauconitic sand or sandy shale; over most of the Athabasca deposit, it directly underlies the datum used in this study, the base of the first regionally correlatable marine shale. There are, however, many areas where the glauconitic sand is not developed (cross sections B-B′ and C-C′, figure 4), in which case the top of the McMurray Formation is placed at the datum. For the purposes of mapping, therefore, the Wabiskaw is included with the upper member of the McMurray Formation. The unit generally occupies an interval from the Wabiskaw datum to approximately 20 m below.

In the western part of the study area, glauconitic "Wabiskaw" sands are developed stratigraphically higher than the projected level of the datum and form significant bitumen reservoirs (figure 2; and cross sections E-E′, F-F′ and the western end of G-G′, figure 5). At the western edge of the study area, these marine sediments directly overlie the pre-Cretaceous unconformity (cross sections E-E′ and F-F′, figure 5).

Lithology

Genetic units in the upper member are generally small, of centimetre to metre thickness, resulting in a complex interbedding of lithologies. This is in contrast to the thick genetic units, both sand and shale, of the middle member. Thin coals and rooted zones are common in the upper member. The sediments are usually highly bioturbated. Sands are generally very fine-grained and argillaceous.

In many outcrop exposures, the upper member is composed of small upward-coarsening sequences a few metres thick, grading from shale or bioturbated argillaceous sand at the base, to better sorted, parallel laminated to wave rippled sands at the top. Palynomorphs of the shales indicate deposition in fresh to very slightly brackish water. Small upward-fining sequences a few metres thick displaying epsilon cross-strata are also present in outcrop. Similar small upward-coarsening and upward-fining units can be seen in the subsurface (cross sections B-B′ and D-D′, figure 4).

Over most of the study area it is easy to differentiate visually between light gray shales that have a "fresh to brackish" palynomorph assemblage and overlying dark gray marine shales. This contact is marked on the cross sections as a line labelled "marine," above which the sediment was all deposited in an open marine environment. Over the central and eastern part of the

Figure 19. McMurray Formation outcrop, Steepbank River. A large set of epsilon cross-strata extends virtually to the top of the formation, overlain by a laterally continuous marine sand (correlative over the Steepbank River outcrop area) representing the initial transgression of the boreal sea. This indicates that deep channels existed in the area until near the close of McMurray time. Compare with the thick sequence of upper member sediment in figure 10. See also figure 20.

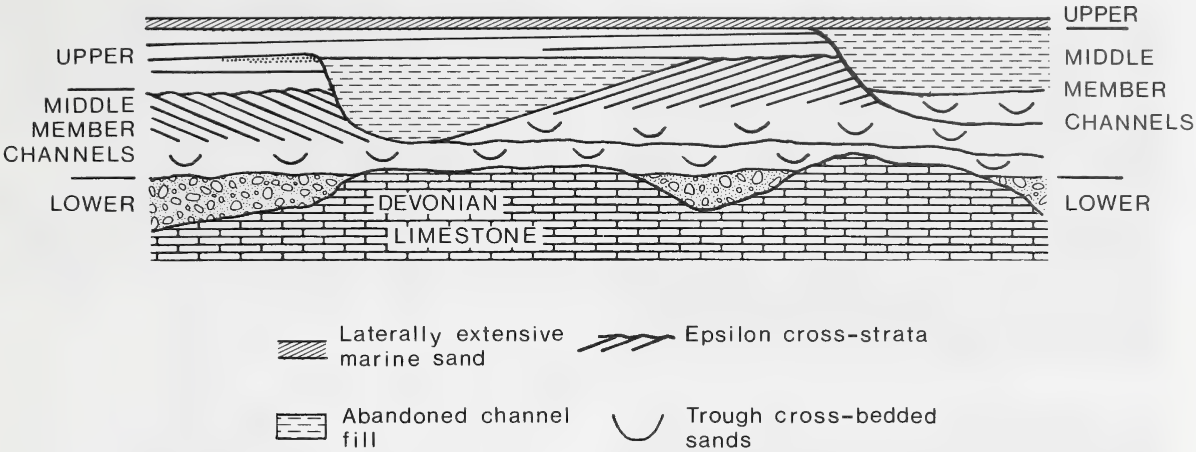


Figure 20. Lateral relationship of thick upper member deposits at the left (for example figure 10) to the channels which existed near the end of McMurray time on the right (figure 19). Small upward-coarsening sequences in the upper member in these areas are interpreted as floodbasin splay deposits of the large channels.

study area, the brackish/marine contact occurs very near the top of the formation, a few metres or less below datum (cross sections A-A′, B-B′, C-C′ and D-D′, figure 4). In the north and west, however, marine sediments are found much lower stratigraphically, sometimes directly overlying upward-fining middle member channels at a level 20 m or more below datum (cross sections F-F′, G-G′ and H-H′, figure 5; and the two eastern-most wells in D-D′, figure 4). In these areas, the marine strata are commonly in the form of very well developed upward-coarsening sequences. Such sequences generally grade from shale at the base, commonly highly bioturbated, through oil sand with thin (1 to 5 cm thick) partings of dark shale, to well-sorted sand at the top (figure 21). Small-scale cross-laminations are the most common sedimentary structures in the sands, with large-scale cross-bedding locally present at the top of the unit. Grain size of the sand is commonly very fine to fine throughout the sequence, but generally shows a slight upward-coarsening trend, to a maximum grain size of coarse sand at the top. The sand bodies appear to be very extensive laterally.

Interpretation

The depositional environment of the upper member in the east and central part of the study area is interpreted as a low lying coastal complex of lakes and brackish bays. In the higher areas, marshes were associated with rivers entering from the east, and possibly the south, and flowing to the sea in the north and west. Outcrop work has shown that the large channels of the middle member survived in some areas until near the end of "upper McMurray time." The small upward-coarsening sequences adjacent to these areas are probably the progradational splay deposits of the channels. A subsurface example can be seen in cross section B-B′ (figure 4) where a laterally extensive coal at the top of the formation in Tp 94, R 7 coincides with an area where channels existed until late in McMurray time, resulting in a major belt of channel sand (maps 4, 6 and 7, in pocket). In this area, the influx of sediment resulted in relatively higher ground and the establishment of vegetation. To the southwest, subaqueous conditions prevailed, with splays from the channels building upward-coarsening sequences into a shallow bay (western part of cross section B-B′, figure 4).

Parallel laminations and wave ripples in well-sorted sands at the tops of some of these sequences indicate reworking by waves as the sequence built above wave base. In places, coal caps the upward-coarsening units, indicating the establishment of vegetation after the filling of a shallow body of water. Bipolar cross-bedding in outcrops of the upper member suggests some tidal influence.

The marine upward-coarsening units in the north and west are interpreted as offshore marine bar deposits. Whereas the small upward-coarsening sequences discussed previously are capped in places by coal or rooted zones, these later marine units show no signs of emergence. The upward-coarsening probably resulted from the migration of offshore bars, rather than from progradation of the shoreline. The sequence is similar to other Cretaceous sand bodies interpreted as offshore bars; Johnson (1978) and Walker (1979) review such sand bodies.

Summary

Since the earliest studies of the McMurray Formation, it has been recognized that the formation as a whole grades from fluvial at the base to marine at the top. The vertical sequence through the formation, from bottom to top, reflects the increasing influence of the approaching boreal sea. Figure 22 summarizes the facies characteristics through the McMurray-Wabiskaw interval.

The lower member, found in lows on the pre-Cretaceous unconformity surface where the formation is greater than about 60 m thick (figure 22), is dominant-

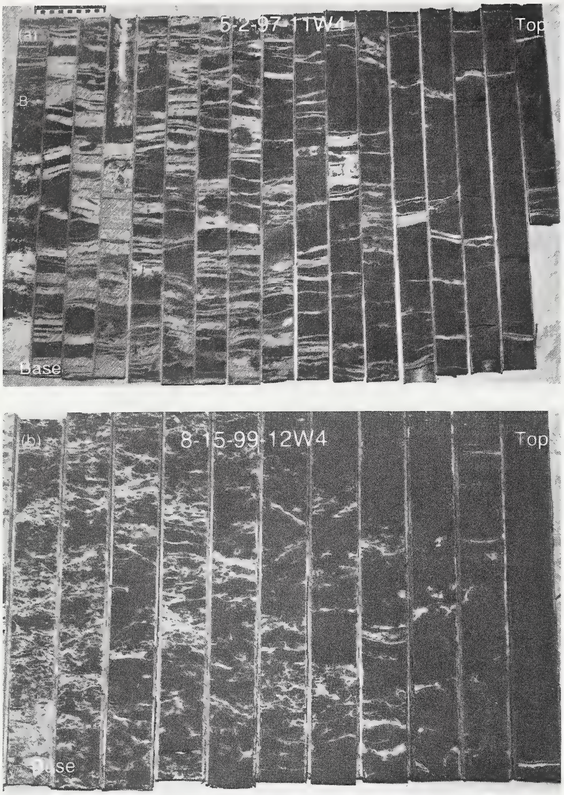


Figure 21. Upward-coarsening offshore marine sands at the top of the McMurray Formation. (a) 5-2-97-11W4; sequence has a sharp base B overlain by interbedded oil sand (dark) and shale (light), with shale interbeds decreasing upwards in amount and thickness; see log of well in cross section D-D', figure 4 (in pocket); core tube lengths 0.76 m, core diameter 5 cm. (b) 8-15-99-12W4; similar to above but sediment is highly bioturbated, with primary sedimentary structures (parallel lamination) only present near top; see log of well in cross section G-G', figure 5 (in pocket); core tube lengths 0.76 m, core diameter 7.6 cm.

ly composed of fluvial channel sands and associated overbank/backswamp fines. Rapid sea level rise during middle member time resulted in a lowering of gradient and a change in channel type from the shallow (5 to 10 m), commonly coarse-grained channels of the lower member, to the deep (20 to 30 m), narrow, sinuous, high suspended load channels of the middle member. Rapid sea level rise also resulted in the rapid accumulation of thick (up to 30 m) sequences of fine-grained sediment in the off-channel areas. These fine-grained sediments, devoid of coal or rooted zones, are interpreted as having been deposited in shallow lakes and brackish bays which existed contemporaneously with the channels. Thick sequences were built up as the floodplain aggraded.

By upper member time, the open sea had invaded the northern and western parts of the study area. In these areas, upward-coarsening offshore bar deposits are found at the top of the formation. Elsewhere, to the south and east, the upper member largely represents deposition in shallow brackish bays; wave and tidal action is more evident than in the underlying middle member. Much of the upper member sediment was probably supplied by the few channels that existed in the southeast until near the end of McMurray time.

At the end of McMurray time, the entire area was transgressed by the boreal sea. Marine shales of the Clearwater Formation blanket the McMurray Formation over most of the study area, while marine Wabiskaw Member sands flank the paleotopographic high in the west.

Mapping of facies

The distribution of facies within the study area is represented in maps 4 and 5 (in pocket) by isolith maps of high energy deposits: clean (nonargillaceous) sands and shale clast breccias, generally found in association with channel sands. Map 4 shows the total thickness of these lithologies, while map 5 is a series of "slice" maps that give some idea of the vertical as well as areal distribution of the sand facies.

The slice maps depict the thickness of sands in successive 20 m intervals through the formation, the first from 60 to 80 m below the Wabiskaw datum, the next from 40 to 60 m below, and so forth up through the formation. In the northeast of the study area, the datum necessary for the construction of these slice maps is missing. In this area, arrows on three of the maps represent general sand trends inferred from the map of total sand thickness.

If deposition of the McMurray Formation occurred as gradual vertical aggradation simultaneously over the entire study area, the slice maps would represent the facies distribution at successive stages from early McMurray to early Clearwater time. As discussed previously this is a first approximation of the mode of McMurray deposition. The major problem is that channels with tops at a high level in the formation (that is, those which existed late in McMurray time) commonly erode deeply through lower levels. In the case of the large middle member channels of the McMurray Formation, for instance, 20 to 40 m of previously deposited sediment may have been eroded, leaving younger channel deposits juxtaposed with much older sediment. Nevertheless, with correlations within the McMurray Formation being virtually impossible, this type of map probably represents the best estimate of sand body trends at different time periods. Since the upper, middle and lower members are generally found in the stratigraphic intervals 0-20 m, 20-60 m and more than 60 m below datum, respectively, the maps (map 5, A to E) approximate sand thicknesses in (A) the lower member, (B) the lower part of the middle member, (C) the upper part of the middle member, (D) the upper member and E) Wabiskaw Member sands overlying the datum.

The limestone symbol on the slice maps indicates the areas where Devonian limestone is present to the top of the interval, and thus represent areas of outcropping

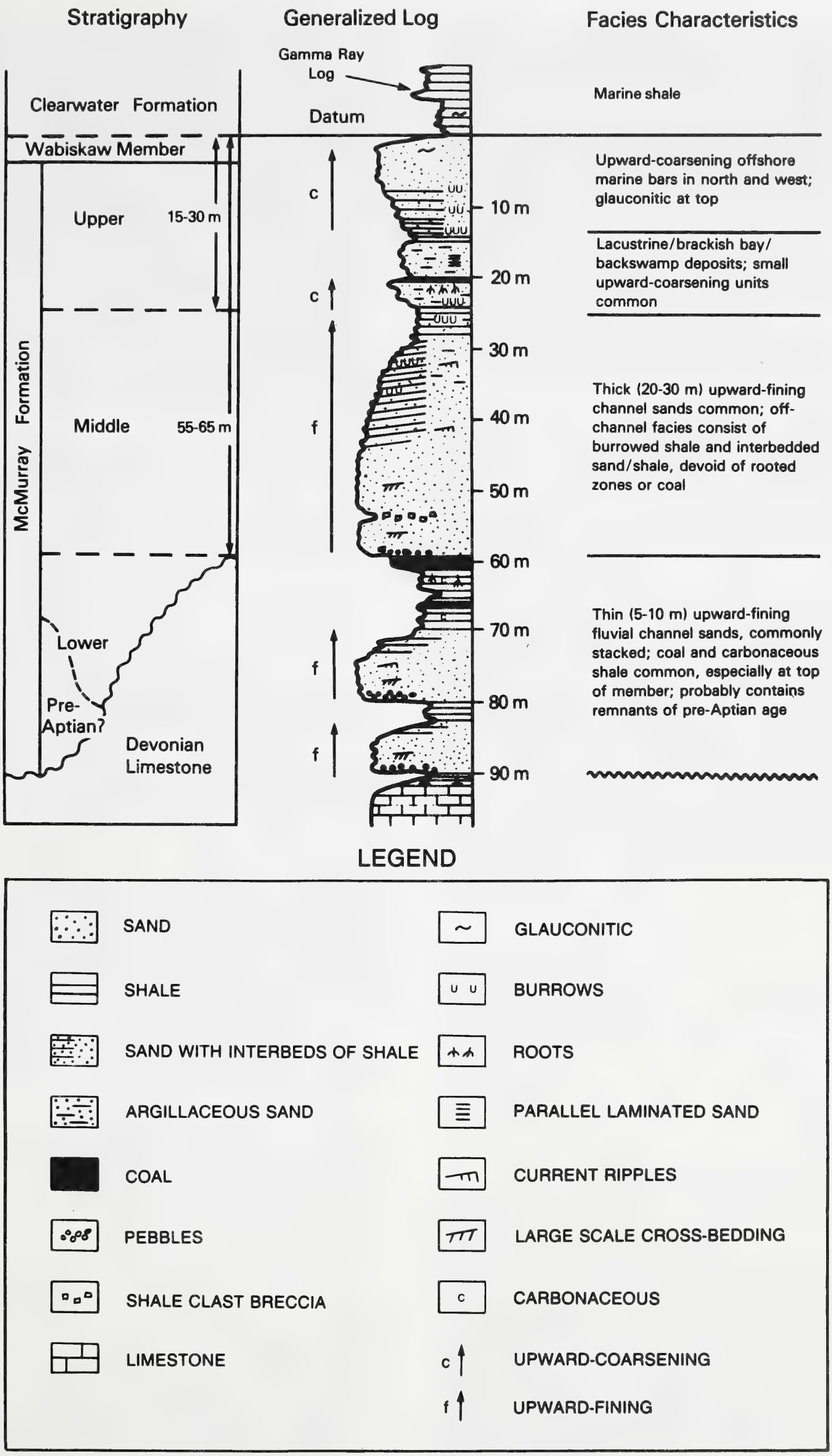


Figure 22. Generalized log of the McMurray Formation, and a summary of the facies characteristics.

Devonian rock at the time of deposition.

Although, for the sake of objectivity, most maps in this report have been left basically as contoured by the computer, considerable latitude has been taken in joining sand trends on the 20 m to 40 m (map 5C) and 40 m to 60 m (map 5B) slices. Since the bulk of the oil sand bodies in this interval (the middle member) are channel deposits which are assumed to follow meander belts, the interpreted trends are thought to reflect more accurately the nature of the sand bodies. Admittedly, because of the sparse well control and the well-known variability of the Athabasca deposit, these trends are rather tenuous; however, qualitative scanning of wells other than those used for control suggests most of the indicated trends are real. The remaining three slice maps (5A, D and E) are as contoured by the computer.

Lower member sands, being generally restricted to areas where the formation is greater than 60 m thick, are present only in the deepest depressions on the paleotopographic surface in the east central part of the study area (map 5A). Lower member sands thus, represent a volumetrically small component of the formation. They are interpreted as fluvial channel deposits, with drainage to the north.

In earliest McMurray time, there appears to have been a regional drainage divide through the southern part of the study area in earliest McMurray time. Not until middle member time (represented by maps 5B and 5C), when the floodplain surface was at a level higher than about 60 m below the present datum, could the drainage cross this divide. Because the floodplain surface available to the streams was expanded, channel sands are much more areally widespread in the middle member. Channel systems in the west developed only near the end of middle McMurray time (map 5C).

In upper McMurray sediments (map 5D), channel deposits are restricted to the southeast quarter of the study area. Sand trends in the north and west represent marine sands, commonly upward-coarsening bar deposits (cross sections E-E′, F-F′, G-G′ and H-H′, figure 5).

Sands above the projected level of the Wabiskaw datum (map 5E) are restricted to the western part of the study area and represent marine bar deposits flanking the Wainright Ridge (a high ground of Devonian limestone) to the west.

Application to in situ recovery

The only method of bitumen recovery which has been proven commercially viable in the Athabasca deposit is open pit mining. Ninety percent of the reserves of the deposit, however, are buried too deeply for surface mining and require in situ recovery methods. Although various in situ techniques have been and are being tested in Athabasca, no process has yet been developed beyond the pilot stage.

Problems in in situ recovery

Most in situ recovery problems in the Athabasca deposit are related to the following reservoir characteristics:

1. an oil viscosity so high that the formation generally lacks both native injectivity and fluid communication between wells
2. a lack of formation energy, such that a drive mechanism is required to recover appreciable quantities of oil
3. an extremely heterogeneous reservoir.

Bitumen in the Athabasca deposit is virtually immobile at reservoir temperature. It behaves more as a solid than as a fluid, filling and plugging the available pore space. The result is that clean, richly oil-saturated sands have extremely low permeability (1 or 2 md; Mungen and Nicholls, 1975; Lennox, 1982), even lower than that of associated argillaceous sands. This low permeability, in turn, makes it difficult to inject fluids into the formation, although such injection is a requirement of most in situ recovery methods. In order to inject fluids at a favorable rate, injection generally has to be either above fracture pressure of the formation or into a permeable zone such as an underlying water sand. Both methods impose significant restrictions on the areas where such a process can be applied (see *Mapping of reservoir characteristics*).

The immobility of the bitumen also results in a lack of fluid communication between wells. In the Athabasca deposit, however, communication between injection and production wells is essential because of the very low formation energy. Even after the bitumen is made mobile (for instance, by lowering its viscosity through heating), the lack of reservoir energy means that a drive mechanism must be applied to move the oil toward the producing well. Achieving and maintaining the communication necessary for a drive process can be a major difficulty, especially where wells are at a commercially viable spacing. The failure of the AMOCO/AOSTRA Gregoire Lake pilot, for example, has been largely attributed to a failure in establishing and maintaining communication (Phillips, 1981).

Aside from the immobility of the bitumen, another reason for difficulty in achieving communication and predicting paths of fluid flow between wells is the complexity of facies in the Athabasca deposit. In contrast to the laterally continuous marine sands of the Clearwater Formation in the Cold Lake oil sands deposit, the bulk of the reservoirs in the Athabasca deposit are non-marine channel sands with extreme facies changes over short distances. Inter-well recovery methods are, thus, at a disadvantage in Athabasca, as horizontal continuity of the reservoir is commonly lacking. Horizontal continuity of cap rock within the McMurray Formation is, moreover, poor compared to the marine shale cap rock over the Clearwater Formation oil sands in the Cold Lake deposit. Only where the rich pay section is found at the top of the McMurray Formation and is overlain by Clearwater shales is there any assurance of a good,

laterally continuous cap rock.

In spite of these problems, research into in situ recovery methods in the Athabasca deposit continues. The reason is clear. In place bitumen reserves are 1600 to 2600 m³/ha·m (1200 to 2000 bbl/acre-ft) and total reserves are comparable to those of the Middle East.

In situ recovery methods and screening criteria

In situ recovery processes require that the viscosity of the bitumen be reduced to a point where it is mobile and can be moved toward a production well. The two most common methods of reducing bitumen viscosity are: applying heat to the formation (thermal recovery methods, figure 23) and using solvents. Solvents, however, because of the quantity needed, their high cost, and the problem of getting them into contact with the oil, will probably be used only as an adjunct to thermal recovery processes (Towson, 1977; Burger, 1978). Of the thermal recovery methods, electrical heating shows promise for the future, as it has the important advantage of not requiring injection of fluid into the impermeable cold reservoir. The cost of electrical energy, however, is high, so it will probably only be used as a pre-heat process to establish communication between injector and producer; electrical pre-heating would then be followed by more conventional thermal recovery methods (Towson, 1979). See Towson (1982) for a brief description of Petro-Canada's electrical pre-heat field pilot in Athabasca.

Of the in situ recovery methods shown in figure 23, the most promising and technologically advanced are steam and combustion.

Steam

Cyclic steam stimulation (or "huff and puff") is a single well process whereby steam is injected into the formation and allowed to "soak" for a period of time to heat the reservoir more uniformly, followed by production from the same well. The injection/production cycle is then repeated. Steam stimulation has the advantage of avoiding the problem of communication between wells. On the other hand, the lack of formation energy in the Athabasca deposit means that very little of the oil is driven to the well during production because the driving forces are restricted to gravity drainage, pressure resulting from the injection cycle, and possibly some

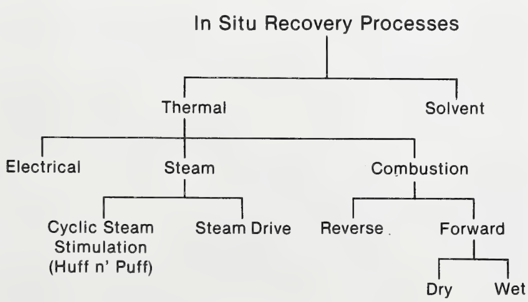


Figure 23. In situ recovery methods.

solution-gas drive (Towson, 1977). Steam stimulation will, therefore, probably be used only to pre-heat the formation prior to a drive process. To date, no cyclic steam stimulation pilot has been successful in Athabasca (Redford, in press).

Steam drive is an inter-well process, with separate injection and production wells arranged in a pattern. Unlike steam stimulation, steam drive, therefore, requires a communication path between injector and producer. The steam heats the bitumen, lowering its viscosity, and the pressure of injection provides the driving force to move the oil from injector to producer. Starting in a hot communication channel, the steam front gradually moves out into the formation in a direction perpendicular to the flow of steam.

Pay thickness requirement

Because the amount of oil recovered increases with pay zone thickness, while the heat loss to overburden and underburden remains constant, the economics of a steam process generally improves with increased reservoir thickness. The minimum pay thickness required for a project in Athabasca to be economically viable will be greater than that for conventional and heavy oil reservoirs because of the higher costs involved in production from oil sands. A review of technically successful enhanced recovery projects (Iyoho, 1978) suggests minimum pay thicknesses of 9 m for steam drive and 15 m for steam stimulation. Peggs (1982) suggests a minimum thickness of 12 m for a combination cyclic steam stimulation/steam drive process in the Cold Lake oil sands deposit, a deposit with somewhat more favorable reservoir characteristics than the Athabasca deposit. In Athabasca, 15 m of pay, uninterrupted by major shale breaks, will probably be required for a steam drive or combination stimulation/drive process (D. Redford, pers. comm.).

Combustion

In situ combustion, or fire flood, is another inter-well process requiring communication paths between injector and producer. Air is injected and the formation ignited, burning a portion of the oil in place. As the burn front advances, oil in the heated zone ahead of the burn is distilled and swept toward the producer by the CO_2, steam and distilled oil fraction that have been produced. The coke remaining in the sand is then burned as fuel as the front continues to advance. In forward combustion, the burn is started in the injector well, so the fire front and injected air both move toward the producer. In reverse combustion, the burn is started at the production well; the fire front gradually moves toward the injector, counter to the flow of air. The COFCAW process (combination of forward combustion and waterflood) involves injecting water along with the air. The water vaporizes in the combustion zone and the steam carries heat forward into the formation.

Combustion processes in oil sands are more difficult to control than those involving steam and are not as well understood. Fewer than a dozen tests have been carried out in oil sands reservoirs and these have been "more often unsuccessful than successful" (Carrigy,

1983). The main problem is the immobility of the bitumen. In heavy oil reservoirs, fluids can move ahead of the combustion front and up to 5 m of pay can be successfully burned in one sweep, the thickness being limited by the effect of gravity override. In oil sands, on the other hand, the hot fluids cannot move ahead through the impermeable cold reservoir and a fire front cannot be propogated as it is in heavy oil. If communication between injector and producer in an oil sand reservoir is by fracture, the burn and movement of fluids are confined to the fracture; if communication is through a permeable bed, such as a water sand, the burn is restricted to a thin zone of oil sand adjacent to the permeable bed. Reverse combustion, which solves the impermeability problem by moving the fluids from the fire front through the hot burned zone to the producer, has also met with very little success in field pilots (Burger, 1978, p. 208).

Pay thickness requirement

Although combustion is technically better suited to thin reservoirs (to minimize the effect of gravity override), the thickness of pay required for a process to be economic in oil sands is much greater than that for heavy oil reservoirs. For example, one way of achieving forward combustion in oil sands is by pre-heating the pay zone so it behaves like a heavy oil reservoir. In this case, the reserves ultimately recoverable must be sufficient to offset the cost of pre-heating. Other methods of combustion currently being tested also need relatively thick reservoirs to be viable, approximately 15 m (D. Redford, pers. comm.).

Thief zones

Because water-bearing sands and gas-bearing sands commonly have permeabilities thousands of times greater than those of associated oil sands, their presence is of great importance to in situ recovery processes. While a thin water sand at the base of a bitumen zone can, as in Shell's pilot in the Peace River deposit, act as a conduit for access to the otherwise impermeable reservoir, finding a laterally consistent thin water zone in Athabasca is highly unlikely. In most cases, water and gas sands act as "thief zones" into which fluids and heat are lost. Such sands are, therefore, usually detrimental to the operation of an in situ process. Imperial's pilots in Cold Lake (Mungen and Nicholls, 1975) and Gulf's Wood River pilot in the Wabasca deposit (Lennox, 1982) provide examples. Combustion processes are more tolerant than steam to underlying thick water sands, as gravity override helps to carry the air up into the burn zone (D. Redford, pers. comm.).

Although gas sands are uncommon through most of the study area, they are common in the west. Water sands locally overlie the reservoir and may themselves be overlain by gas (cross section E-E'). These sands were previously part of the gas cap, but the gas has bled off and, because the oil is now immobile, the pore space has filled with water. Overlying gas or water significantly increases the chances of gravity override. The problem is more pronounced in combustion than in steam processes because of the greater difference in density between oil and air. In combustion projects, therefore, it may be desirable to have a reservoir with poor vertical permeability, such as one containing numerous thin shale beds. The marine upward-coarsening units in the north and west of the Athabasca deposit could, thus, be good candidates for combustion, providing there is no overlying gas. Injection at the base of an upward-coarsening sequence, with override then tending to move fluids up into the richer part of the sequence, is preferable to using the process in an upward-fining channel deposit where the richest sand at the base is easily bypassed. The upward-coarsening marine sands also have more lateral continuity than the channel deposits.

Overburden as a screening criterion

The Athabasca deposit can be divided into three zones on the basis of depth of overburden: the surface mineable area, with less than 50 m of overburden; the in situ area, where there is enough overburden to contain the pressures involved in most in situ recovery methods — pressures required for fracturing the formation as well as displacing the oil; and an intermediate area that is too deep for surface mining, but too shallow for most conventional in situ recovery methods. The amount of overburden necessary for an in situ recovery project is commonly quoted as 150 m (Burger, 1978; Janisch, 1979), while Allen (1979) suggests 200 m as a minimum, with 300 m preferred. Some successful field pilots in Athabasca, however, have had less than 100 m of overburden (D. Redford, pers. comm.). The quality of overburden is probably the determining factor: as little as 75 m may be sufficient, if there is a competent Clearwater shale overlying the reservoir (D. Redford, pers. comm.).

Except for the area near the Athabasca River, where it has been eroded, Clearwater shale overlies the McMurray Formation (or the oil saturated Wabiskaw sands in the north and west), but there may be a considerable thickness of lean McMurray Formation between the top of the reservoir and the base of the shale. Cap rocks within the McMurray Formation are generally discontinuous and of variable character, becoming silty or sandy over short distances. For cap rock, therefore, the more attractive reservoirs are those where rich oil sand pay extends to near the top of the McMurray Formation.

Another important factor related to depth of overburden is the change in the orientation of fractures with depth. Because fracturing the formation is a method commonly used to achieve injectivity into the formation and communication between wells, it is advantageous to be in an area where fracture planes are horizontal rather than vertical. Horizontal fractures contact more of the reservoir and increase the chances of intersecting other wells. Dusseault (1977) found that fractures are probably horizontal above 350 m depth and vertical below 450 m. Field tests indicate that horizontal fractures occur at depths of less than 300 m (Redford, in press). At depths greater than this, currently, the only effective means of achieving horizontal communication

in a reservoir without existing permeable zones is through the drilling of horizontal wells.

Logging method for reservoir characterization

One objective of this study was to form a database for mapping various reservoir characteristics and, more specifically, for mapping which areas of the deposit are, on the basis of those characteristics, best suited to a particular recovery technique. The screening criteria for the various recovery methods, however, are at best poorly known and will probably change with time as existing processes are refined and new processes developed. In order to make the database flexible enough to permit searching for different criteria in the future, the lithology and oil saturation data were recorded as a continuous log for each control well throughout the McMurray/Wabiskaw interval.

Sediments were categorized into one of 17 lithology/saturation types (table 1 and figure 24). Abbreviation codes beginning with F represent fine-grained sediments (silt and clay); those beginning with S represent a dominantly sand lithology. An attempt was made to keep the classification as simple as possible, while recognizing lithological differences that would be important in oil sands recovery processes, especially oil saturation and relative permeability. Simplicity was necessary because core was unavailable for two-thirds of the control wells; most classification types were therefore made general enough to be interpreted from geophysical logs alone. Because of the limits of log interpretation, individual designations were not applied to intervals less than 60 cm thick.

The classification scheme is based on the observation that the lithology, oil saturation and permeability of sediments in the Athabasca deposit are interdependent. Except in the water sands commonly found at the base of the formation and gas sands at the top, oil saturation in the Athabasca deposit is closely linked to lithology: clean porous sands are virtually always richly saturated with bitumen. Decreasing oil content is generally caused by an increase in the percentage of fines (Carrigy, 1962; Fertl, 1979). The permeability of oil free sands in the Athabasca deposit is usually very high, up to several darcies; however, because most available pore space is filled with immobile bitumen, the permeability of rich oil sand is very low, approximately 1 or 2 md (Mungen and Nicholls, 1975; Lennox, 1982). In most Athabasca reservoirs, in fact, the best permeability can be expected in argillaceous sands that were less permeable to oil at the time of migration and now have slightly higher water saturations.

The classification types S, Sa, Fs and F (figure 24a and table 1) represent a continuum of lithologies within the oil saturated portion of the formation, with increas-

Table 1. Lithology/saturation types

	Code	Description	Oil saturation percent by weight
1. Single lithology			
a) Within oil saturated interval	S	Oil sand	>8
	Sa	Oil sand,argillaceous	4-8
	Fs	Shale, sandy	2-4
	F	Shale	0-2
b) Undersaturated with respect to oil	S1	Lean sand	4-8
	Sw	Water sand	0-4
	Swa	Water sand, argillaceous	0-4
2. Interbedded lithologies a) Bulk oil saturation >8% by weight	S/F	Oil sand (>50%) with numerous interbeds of shale up to 1 m thick	>8
	*Sf	Oil sand with occasional (every 15-60 cm) thin (1-10 cm) shale breaks	>8
	*Sff	Oil sand with abundant (every 15 cm or less) thin (1-10 cm) shale breaks	>8
b) Bulk oil saturation <8% by weight	F/S	Shale (>50%) with numerous interbeds of oil sand up to 1 m thick	4-8
3. Other lithologies	Sg	Gas sand	
	*Fb	Shale clast breccia in oil sand matrix	
	C	Coal, carbonaceous shale	
	HS	Hard streak (ironstone, calcite cement)	
	L	Limestone	

*Recognizable only in core

ing fines content and resultant decreasing oil saturation. An oil saturation of approximately 8 percent (by weight) was chosen as the cutoff between rich oil sand (S) and argillaceous oil sand (Sa), with sandy shale (Fs) less than 4 percent and shale (F) less than about 2 percent. Sa and Fs may represent either homogeneous lithologies or interlaminated sand and shale. Permeability is very low in rich oil sands, increasing slightly in argillaceous oil sand, then decreasing again through sandy shale and shale.

The remaining lithologies on figure 24a (Sl, Sw, Swa,) are undersaturated with respect to oil and are generally found in the lower portions of the formation, below the oil/water contact. These lithologies have higher permeabilities than oil saturated sediment of the same lithology. Classification types Sw (water sand) and Sl (lean oil sand) are clean, porous sands with low oil saturation (0 to 4 percent and 4 to 8 percent, respectively). Swa represents argillaceous water sand (0 to 4 percent oil by weight). In places, original porosity in the sands below the oil/water contact is filled by kaolinite. In such cases, permeability may be very low.

Oil sands and shales interbedded on the scale of a decimetre to a metre are represented by the codes S/F, where sand dominates, and F/S, where shale dominates (figure 24b). S/F is defined as having an estimated bulk oil saturation greater than 8 percent; F/S represents intervals with an average saturation of less than 8 percent. The two codes represent approximately where the sand/shale ratio is greater than/less than 50 percent. These codes are used mostly in wells for which core was not available and large intervals show a highly serrated resistivity curve. Even in uncored wells, shale breaks as thin as 10 cm thick can commonly be recognized on a resistivity log.

Two subcategories of rich oil sand, recognizable only in core, were differentiated because, although very thin shale breaks in a pay zone may not cause a response on geophysical logs, they may significantly affect fluid flow in an in situ recovery process. Rich oil sands (greater than 8 percent oil saturation by weight) with thin (1-10 cm) shale partings are classified as Sf or Sff, depending on the frequency of the partings (table 1 and figure 24b). This type of interbedding is especially common in the upward-coarsening marine bar sand at the top of the McMurray Formation; all four interbedded types (S/F, F/S, Sf and Sff) are common in the upper portions of upward-fining channel deposits.

Detailed differentiation of dominantly shale interbedded lithologies was considered of marginal value and was, therefore, not attempted. A shale with numerous thin interbeds of sand, for instance, was simply coded as a sandy shale.

Another common lithology recognizable only in core is a shale clast breccia in an oil sand matrix (Fb) (figure 15). Although it generally resembles shale on geophysical logs, depending on the percentage of shale clasts, the unique characteristics of this lithology make differentiation desirable.

Other lithologies recorded are gas sands (Sg), coal and carbonaceous shale (C), hard streaks (HS), and limestone (L). Hard streaks are generally sideritic mudstone concretions in the McMurray Formation, with some calcite cemented sandstones in the Clearwater Formation. Limestones are generally restricted to the underlying Devonian rock.

The degree of confidence in the interpreted data was recorded as a "quality code" for each reading, on a scale of 1 to 5:

1. good quality geophysical logs, with core
2. good logs with some oil saturation analyses
3. good logs with no analyses, or poor logs with good analyses
4. poor logs with poor analyses
5. poor logs with no analyses

In some areas of the deposit (for example, Tp 93, R 14 to 18 W4), no control wells were used because the quality of data was too poor to justify detailed analysis. A map showing the quality of data (the average for each well) is shown in figure 25.

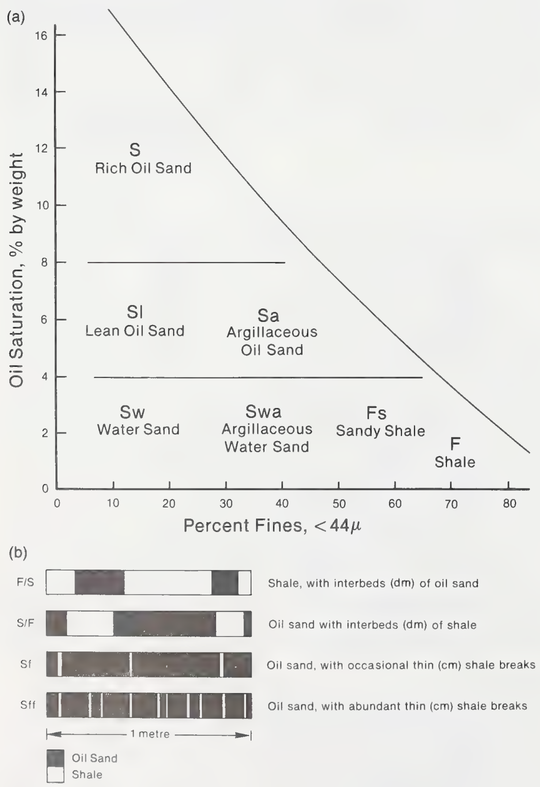


Figure 24. Classification of sediment types by lithology and oil saturation (a) single lithologies, (b) interbedded oil sand and shale. See discussion in text and a complete listing of classification types in table 1.

Mapping of reservoir characteristics

Of the many reservoir characteristics that must be taken into account in the siting of an in situ recovery operation, some of the most basic and most amenable to regional mapping are shown in maps 6 to 9 (in pocket).

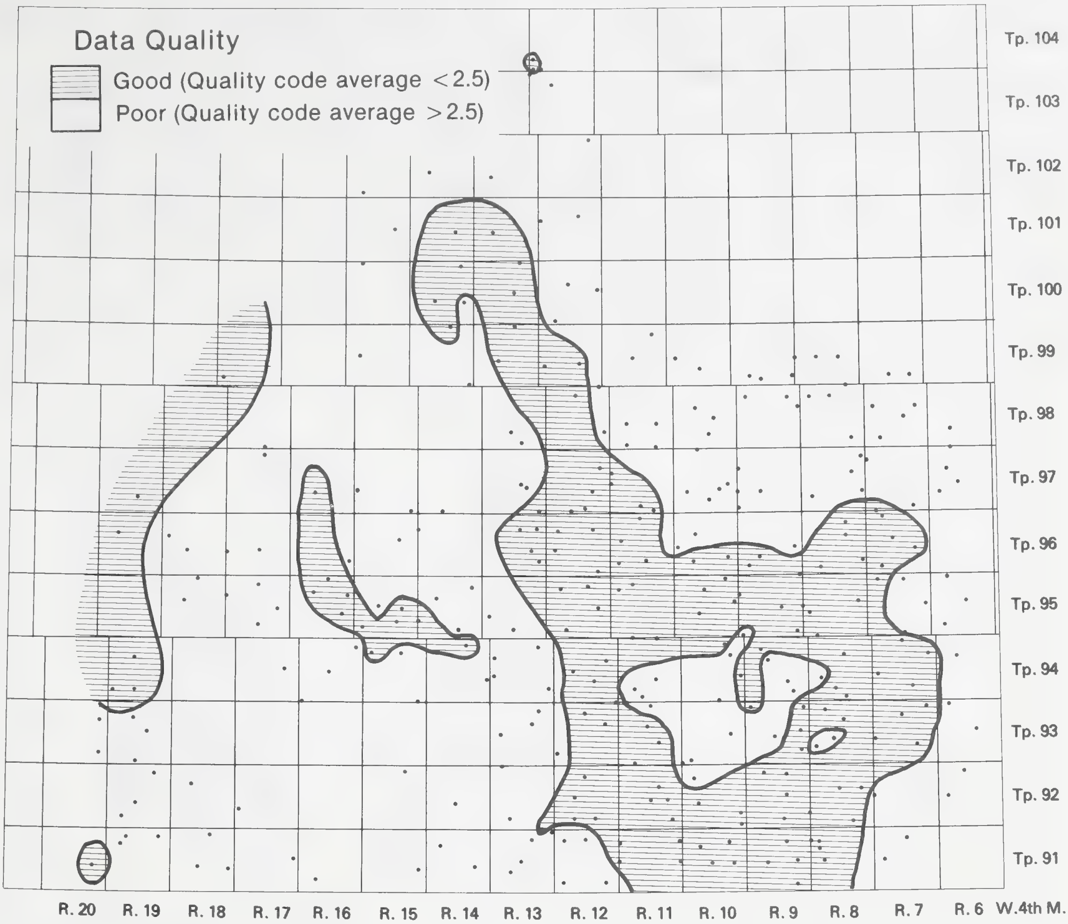


Figure 25. Map of average data quality for each well. The blank areas are those where data are somewhat questionable due to poor quality geophysical logs or lack of oil saturation analyses. Good quality well control (largely determined by how recently wells have been drilled in the area) is generally found in the richer parts of the deposit.

Pay thickness (map 6)
This map represents the total thickness of rich oil sand (S, Sf, Sff and S/F of figure 24 and table 1) in each well, regardless of the thickness of individual beds.

The total thickness of rich pay depends on the distribution of clean (mostly channel) sands and the thickness of the formation. The wide trend of thick pay through the central eastern part of the study area corresponds approximately to the paleovalley in this area, as shown on the McMurray Formation isopach (map 2). The major differences between pay thickness and total thickness of clean sands (map 4) are due to the local presence of thick water sands underlying the reservoir.

Uninterrupted pay thickness (map 7)
In situ processes generally require a reasonably thick section of oil sand containing no major shale breaks that would limit the vertical movement of fluids. Map 7 represents the thickest interval of rich oil sand (greater than 8 percent oil by weight) containing no breaks of shale or argillaceous oil sand greater than 3 m thick. The choice of 3 m as the minimum thickness of a break that divides a reservoir in two is arbitrary. In an actual in situ operation, a detailed study of the nature and lateral extent of the breaks would have to be made; nevertheless, the map gives some idea of the vertical continuity of reservoir sands and the areas where thick sections may be found.

Bottom water sand thickness (map 8)
Map 8, representing the total thickness of water-bearing sands (Sw, Swa and Sl; figure 24 and table 1) underlying the oil/water contact, indicates fairly well defined areas where basal aquifers could be expected. These water sands, however, are not always in direct contact with the reservoir and, if they are separated from it by a thick enough interval of less permeable material, they should have no effect on the process. The following data suggest that, in the mapped "bottom water zone," one can expect the reservoir to be actually

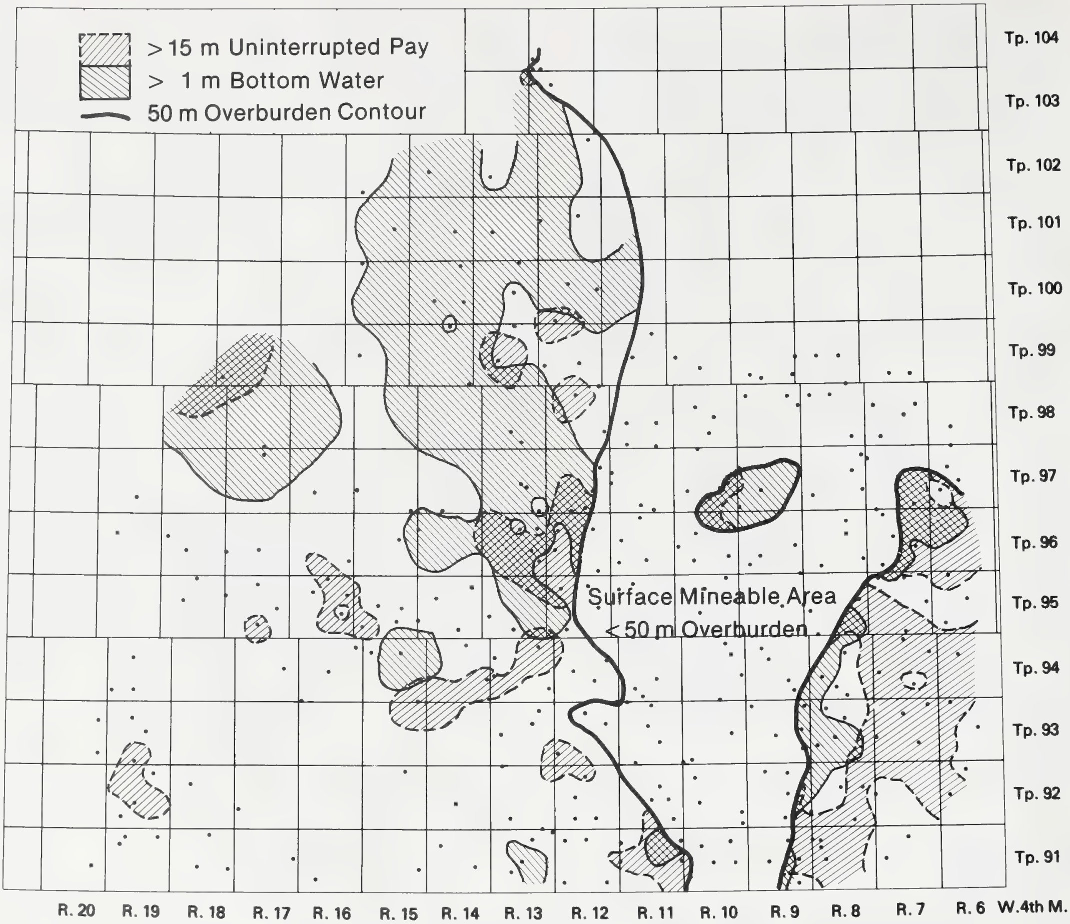


Figure 26. Composite map showing areas with greater than 15 m of uninterrupted pay (from map 7) and areas with greater than 1 m of bottom water sand (from map 8). The areas of overlap are those which have a thick enough section of oil sand to support an in situ recovery project and a bottom water sand which, depending on the recovery process and thickness of the sand, may be beneficial (for achieving injectivity) or detrimental (acting as a thief zone). It should be stressed that bottom water sands in the area shown are only in contact with the reservoir in about one-third of the cases.

in contact with underlying water sands in about one-third of the cases: of the 73 wells on the map that contain water sands and have more than 5 m of overlying uninterrupted pay, in 26 cases (36 percent), the bottom water sand is in contact with the reservoir; of the 35 wells with bottom water and 15 m or more of uninterrupted pay, 10 (29 percent) have water sands in contact with the reservoir. "In contact" is here defined as having less than 3 m of shale or argillaceous sand between the two.

The thickness of the formation is the primary factor controlling the distribution of water sands since they are found in lows below the oil/water contact. In the central part of the study area, the formation is commonly oil saturated to a depth of 80 m or more below the Wabiskaw datum, with water sands below this depth (cross section D-D', figure 4). To the northwest, however, the oil water contact rises to less than 40 m below datum (cross sections G-G' and H-H', figure 5). The result is widespread water sands in the northwest, even though the formation is relatively thin.

Figure 26 is a superposition of maps 7 and 8, showing the areas of the deposit with more than 15 m of uninterrupted pay (enough to support an in situ recovery operation) and more than 1 m of bottom water. Areas of overlap indicate either the areas of interest for a process requiring a bottom water zone or areas to be avoided if bottom water would be detrimental to the process.

Overburden thickness (map 9)

Map 9 represents the depth to the first sand with oil saturation greater than 4 percent by weight. Depth of overburden is controlled mainly by present day topography, the near-surface part of the deposit being in the broad valley of the Athabasca River, with overburden increasing to Muskeg Mountain in the southeast

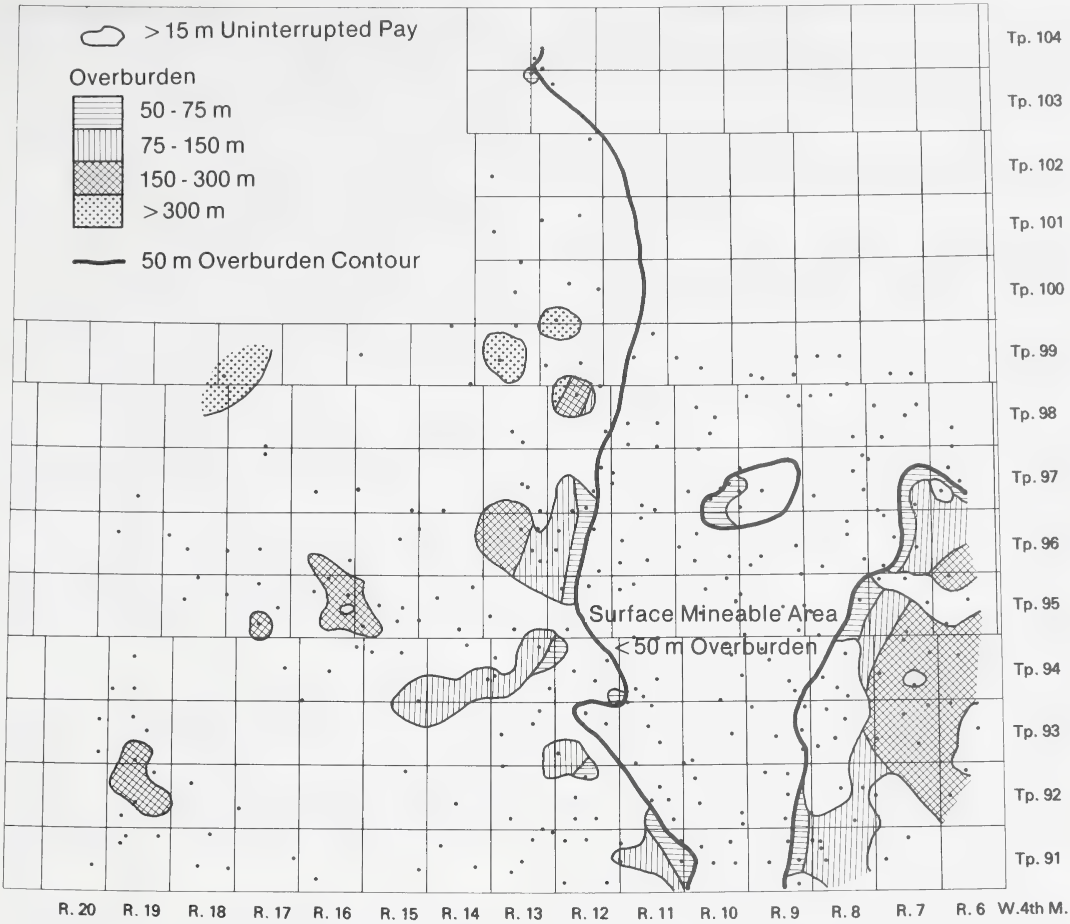


Figure 27. Composite map showing areas with a thick enough section of oil sand to support an in situ recovery project (15 m of uninterrupted pay, from map 7) and the overburden thickness in those areas (from map 9). Overburden thickness is important in determining whether high pressure recovery processes can be applied and whether fractures will be horizontal or vertical (see text for discussion). Most of the reserves in this part of the deposit are within the surface mineable area of less than 50 m overburden.

and the Birch Mountains in the northwest. The thick overburden in the center of the mineable area (Tp 97, R 9) marks another topographic high, the Fort Hills.

Figure 27, a superposition of maps 7 and 9, shows the amount of overburden in areas with more than 15 m of uninterrupted pay. It broadly defines the surface mineable area (less than 50 m overburden), the area where recovery of any kind is doubtful because of the shallowness of overburden (50-75 m), an intermediate area where in situ recovery is possible and fractures are horizontal (75 to 300 m) and the area where fractures are probably vertical (greater than 300 m). See the earlier discussion of overburden as a screening criterion.

Conclusion

In situ recovery projects in the Athabasca Wabiskaw-McMurray oil sands deposit have met with very limited success, primarily because of the difficulty in achieving and maintaining hot communication between wells (Redford, in press). The geological complexity of the channel sand facies is a major factor in this difficulty. A better understanding of the geometry and facies characteristics of the oil sand bodies is, therefore, an important step toward successful recovery operations.

In future in situ recovery projects in Athabasca, the characteristics of the individual reservoir will determine, to a large extent, the nature of the recovery process. This is in contrast to many past experiences where a process to be tested was forced upon a reser-

voir to which it was not particularly well suited. Mapping of reservoir characteristics is a necessary step in determining where a process may best be applied. As shown in figures 26 and 27, the areas of the deposit that pass the screening criteria for a particular recovery process may be very limited.

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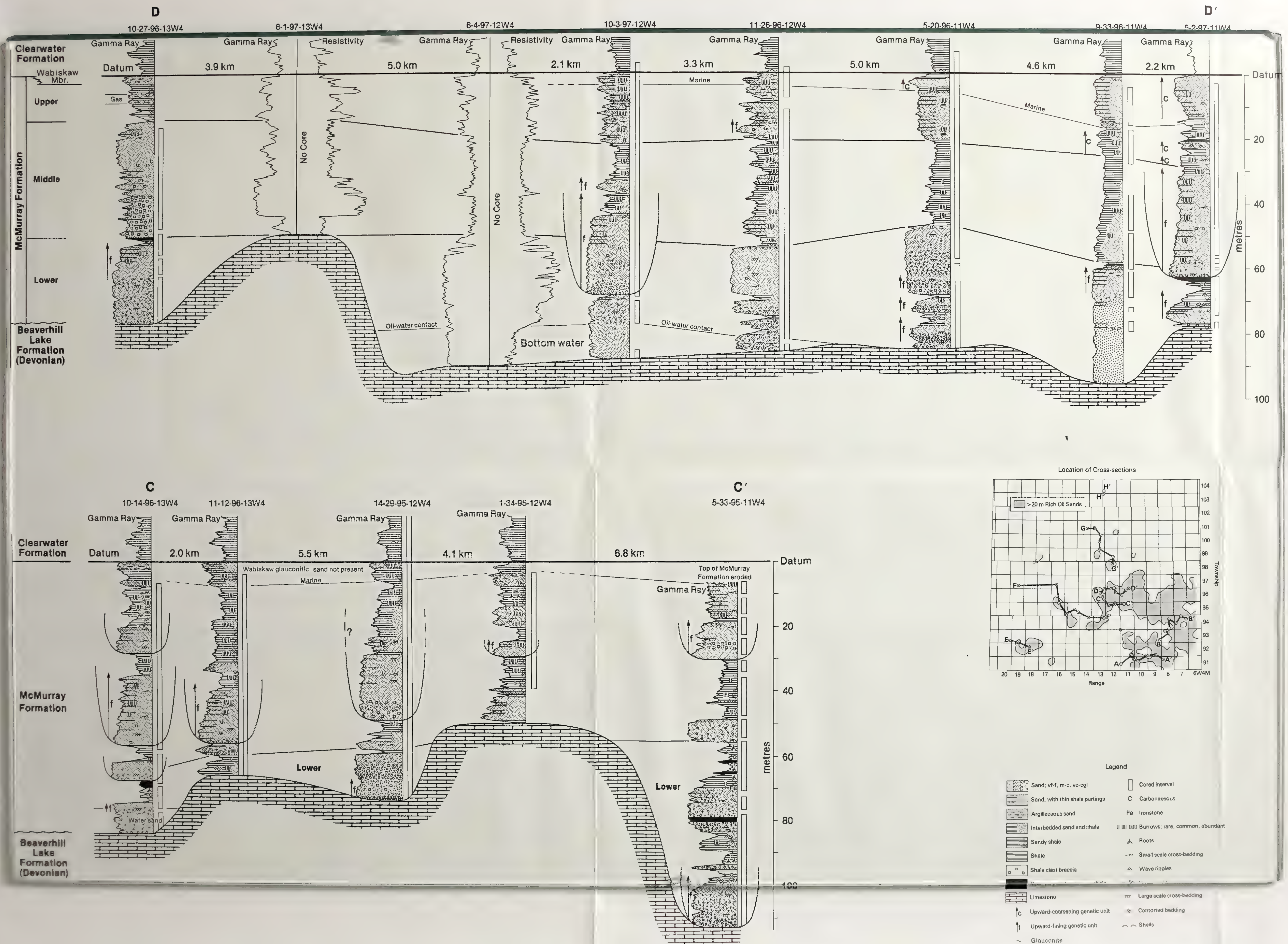

D
D′
10-27-96-13W4
6-1-97-13W4
6-4-97-12W4
10-3-97-12W4
11-26-96-12W4
5-20-96-11W4
9-33-96-11W4
5-2-97-11W4
Gamma Ray
Resistivity
Clearwater Formation
Datum
Wabiskaw Mbr.
3.9 km
5.0 km
2.1 km
3.3 km
5.0 km
4.6 km
2.2 km
Upper
Gas
Middle
Lower
McMurray Formation
Beaverhill Lake Formation (Devonian)
No Core
Marine
Oil-water contact
Bottom water
metres
C
C′
10-14-96-13W4
11-12-96-13W4
14-29-95-12W4
1-34-95-12W4
5-33-95-11W4
2.0 km
5.5 km
4.1 km
6.8 km
Wabiskaw glauconitic sand not present
Top of McMurray Formation eroded
Water sand
Location of Cross-sections
>20 m Rich Oil Sands
Township
Range
Legend
Sand; vf-f, m-c, vc-cgl
Sand, with thin shale partings
Argillaceous sand
Interbedded sand and shale
Sandy shale
Shale
Shale clast breccia
Limestone
Upward-coarsening genetic unit
Upward-fining genetic unit
Glauconite
Cored interval
Carbonaceous
Ironstone
Burrows; rare, common, abundant
Roots
Small scale cross-bedding
Wave ripples
Large scale cross-bedding
Contorted bedding
Shells

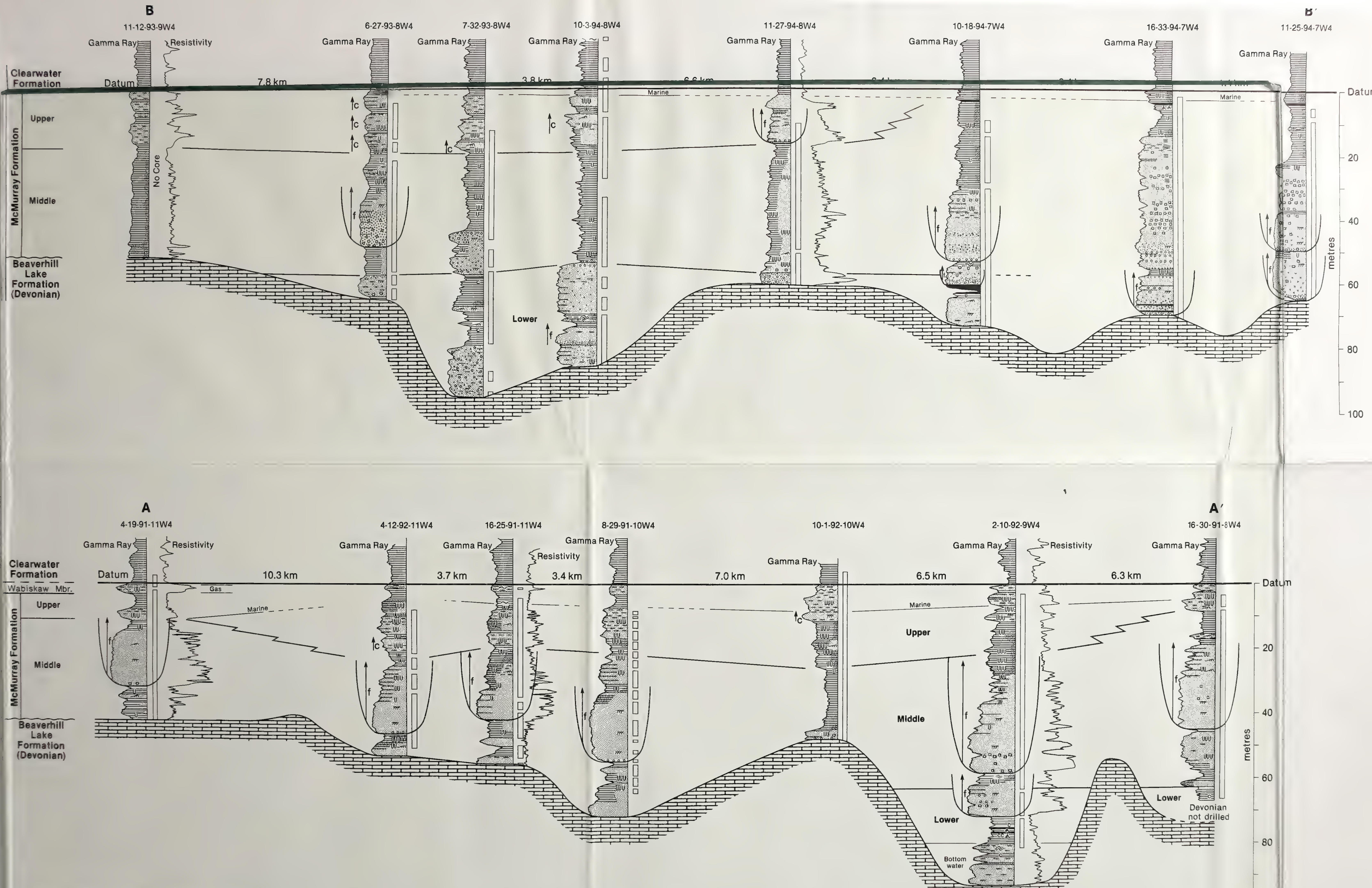
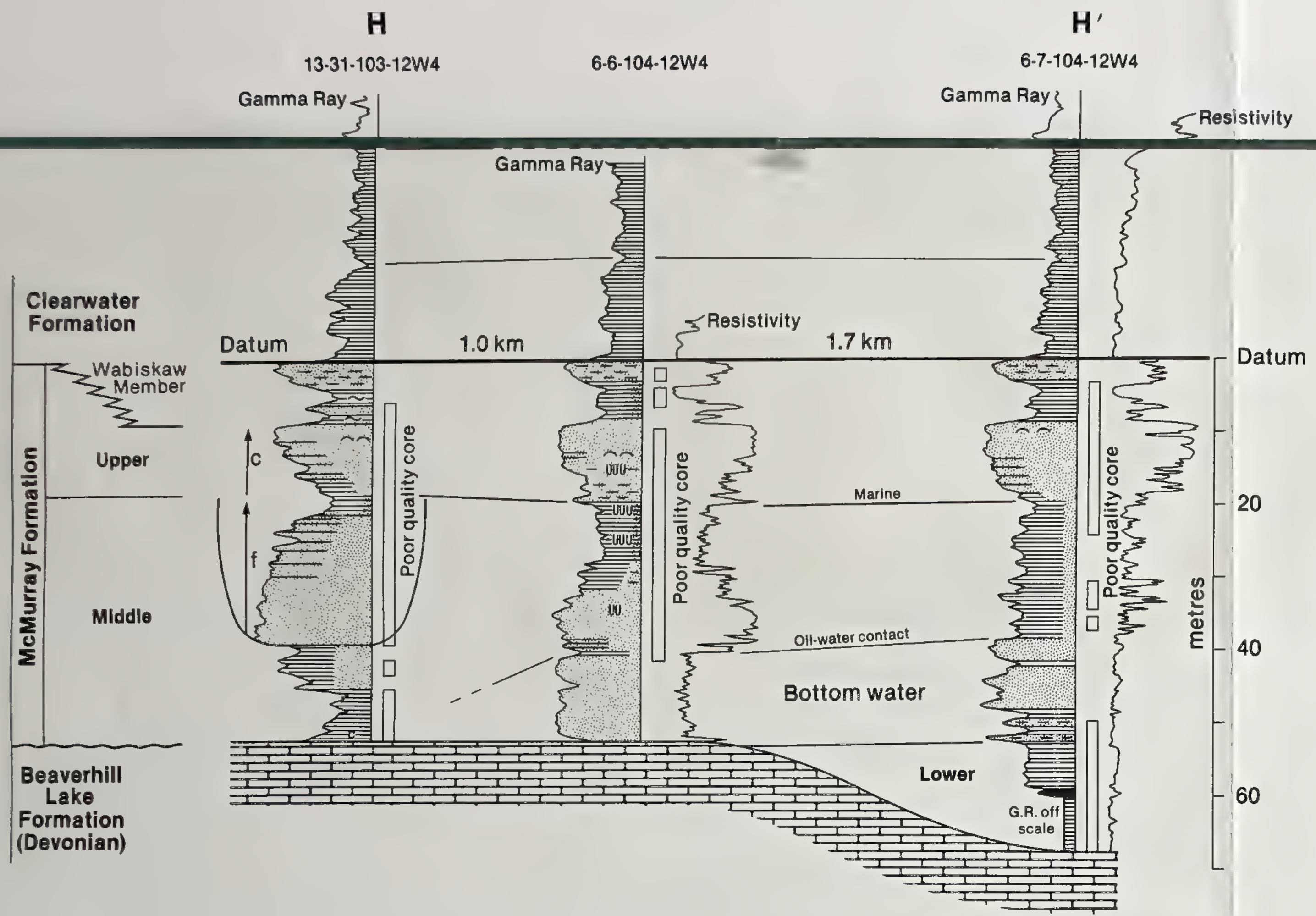
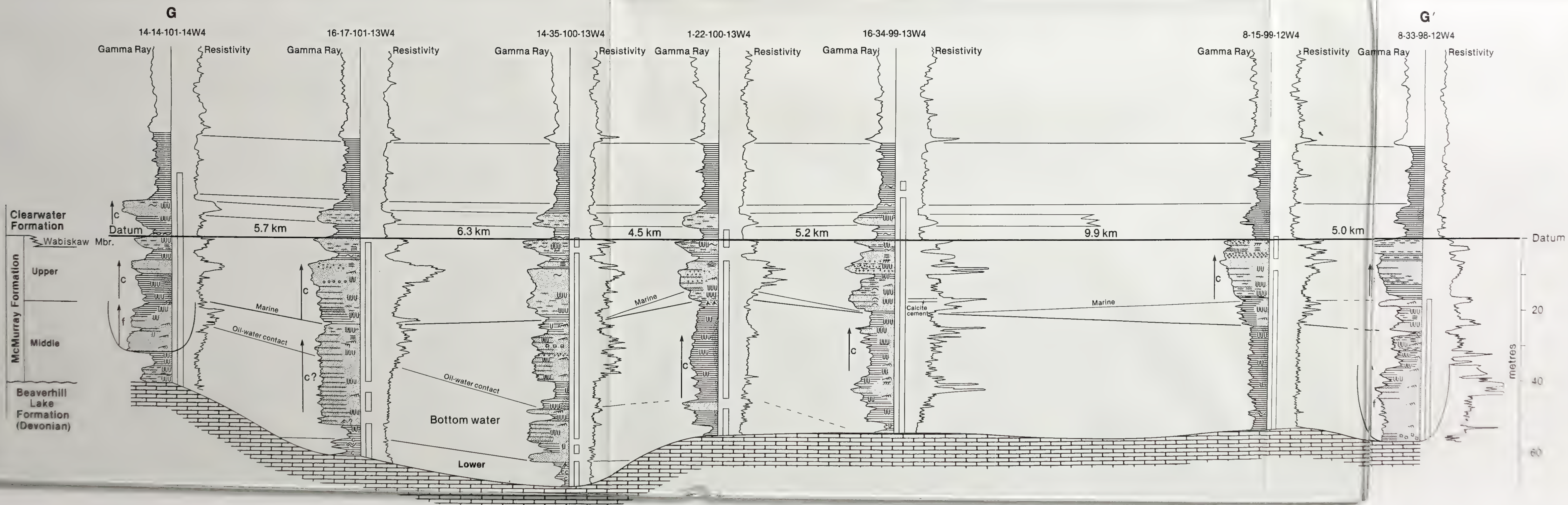


FIGURE 4 Stratigraphic cross-sections of the McMurray Formation.


H
13-31-103-12W4
6-6-104-12W4
H′
6-7-104-12W4
Gamma Ray
Resistivity
Clearwater Formation
Datum
1.0 km
1.7 km
Wabiskaw Member
Upper
McMurray Formation
Middle
Poor quality core
Marine
Oil-water contact
Bottom water
Lower
G.R. off scale
Beaverhill Lake Formation (Devonian)
20
40
60
metres


G
14-14-101-14W4
16-17-101-13W4
14-35-100-13W4
1-22-100-13W4
16-34-99-13W4
8-15-99-12W4
G′
8-33-98-12W4
Gamma Ray
Resistivity
Clearwater Formation
Datum
5.7 km
6.3 km
4.5 km
5.2 km
9.9 km
5.0 km
Wabiskaw Mbr.
Upper
McMurray Formation
Middle
Marine
Oil-water contact
Calcite cement
Bottom water
Lower
Beaverhill Lake Formation (Devonian)
20
40
60
metres

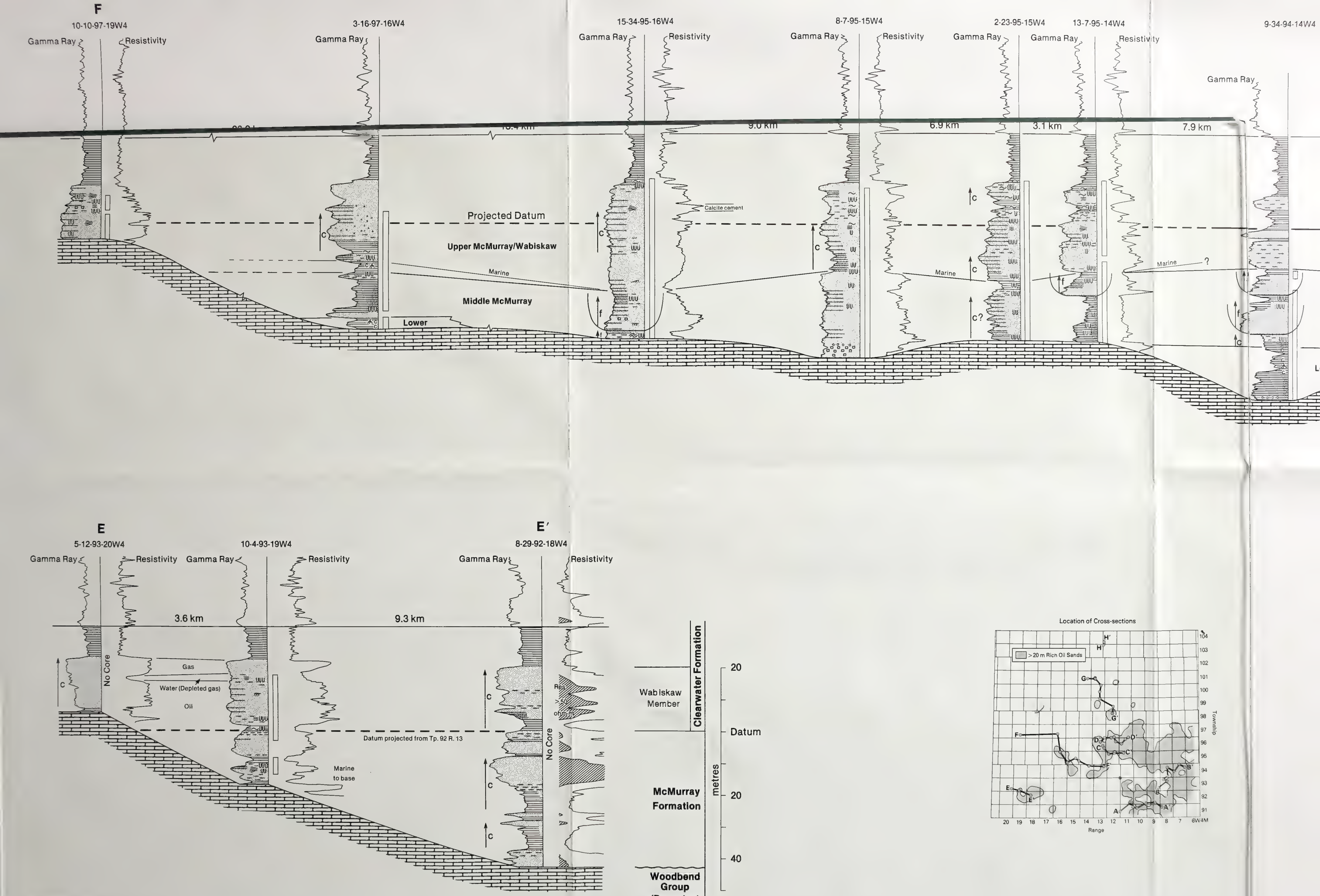
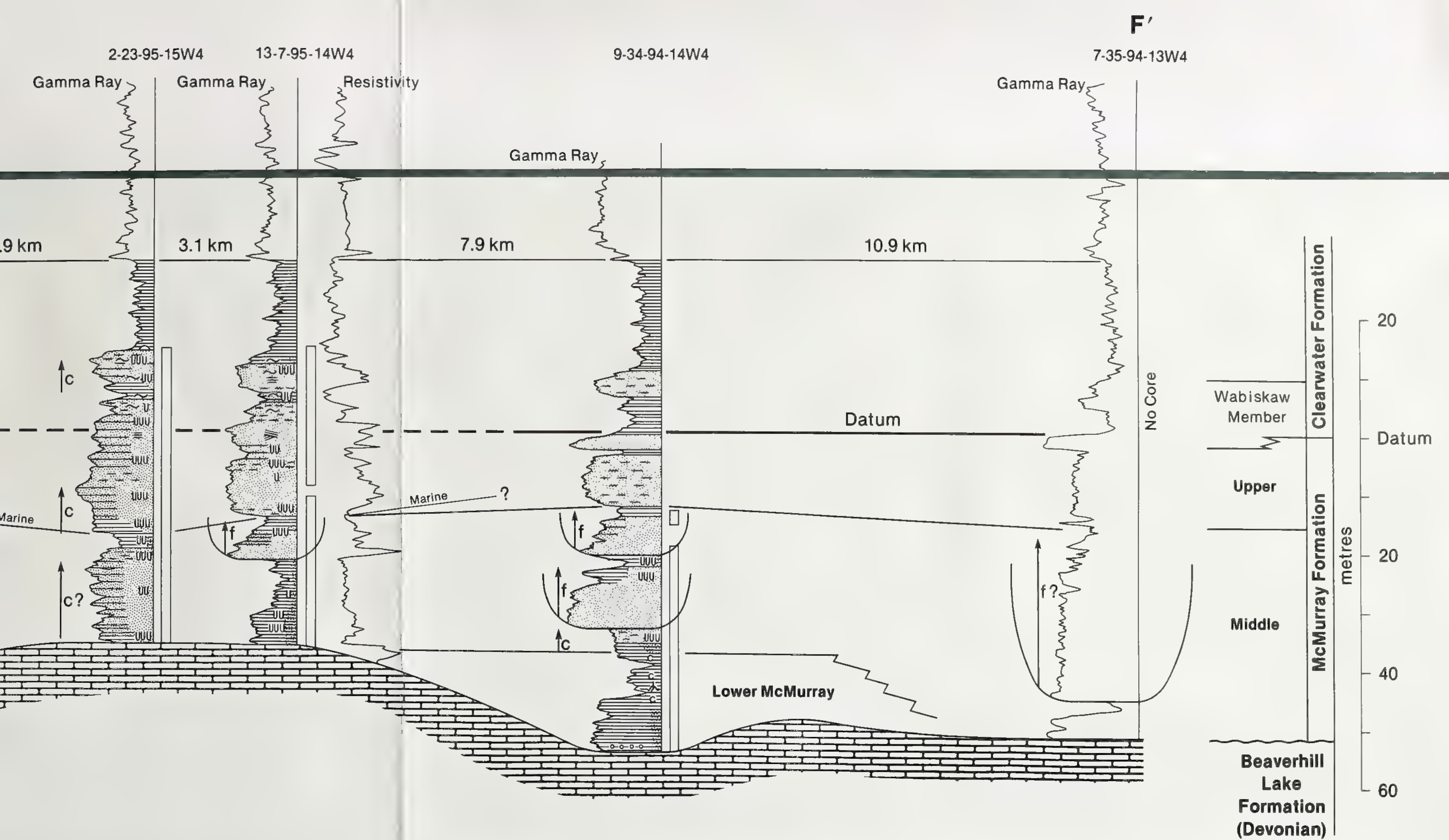
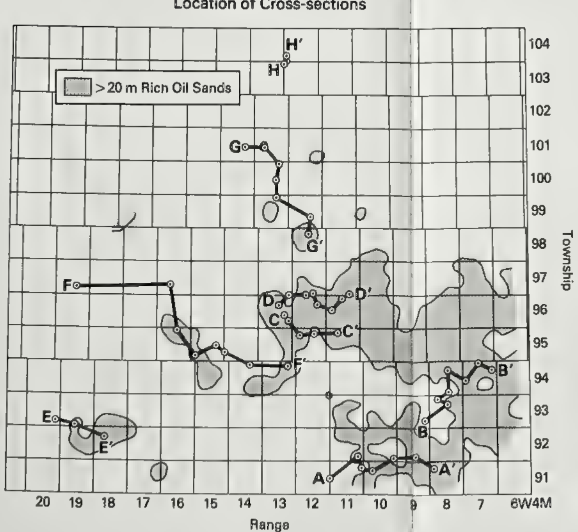


FIGURE 5. Stratigraphic cross-sections of the McMurray Formation and lower part of the Clearwater Formation.



Location of Cross-sections



Legend

- Sand; vf-f, m-c, vc-cgl
- Sand, with thin shale partings
- Argillaceous sand
- Interbedded sand and shale
- Sandy shale
- Shale
- Shale clast breccia
- Coal, very carbonaceous shale
- Limestone
- c Upward-coarsening genetic unit
- f Upward-fining genetic unit
- Glauconite
- Cored interval
- C Carbonaceous
- Fe Ironstone
- U UU UUU Burrows; rare, common, abundant
- Roots
- Small scale cross-bedding
- Wave ripples
- Horizontal lamination; low angle
- Large scale cross-bedding
- Contorted bedding
- Shells

McMurray Formation Structure
Athabasca Oil Sands North

Map 1

P.D. Flach

Published 1984

To accompany Alberta Research Council Bulletin 46

Cartography by Alberta Research Council, Graphic Services, J. Matthie

SCALE 1:250,000

Kilometres 5 0 5 10 15 20

Miles 5 0 5 10

Structure contours on Wabiskaw Datum (approximating McMurray Formation [illegible] the western part of the map area where the marker is not developed, an equi[illegible] been estimated (see text).

- >350 m
- 325 - 350 m
- 300 - 325 m
- 275 - 300 m
- 250 - 275 m
- <250 m

- • Well cor[illegible]
- Erosiona[illegible]
- Contour

ALB
RESEA
COU

Natural Reso
Alberta Geol

0 Kilometres

40 Miles

McMurray/Wabiskaw i

10 to 15 m

15 to 20 m

top of interval.

area where datum is

a where datum is ab

wells have been drill

n, and in the central

roded.

McMurray Formation Structure
Athabasca Oil Sands North

Map 1

P.D. Flach

Published 1984

To accompany Alberta Research Council Bulletin 46

ALBERTA RESEARCH COUNCIL

Natural Resouces Division
Alberta Geological Survey

Cartography by Alberta Research Council, Graphic Services, J. Matthie

SCALE 1:250,000

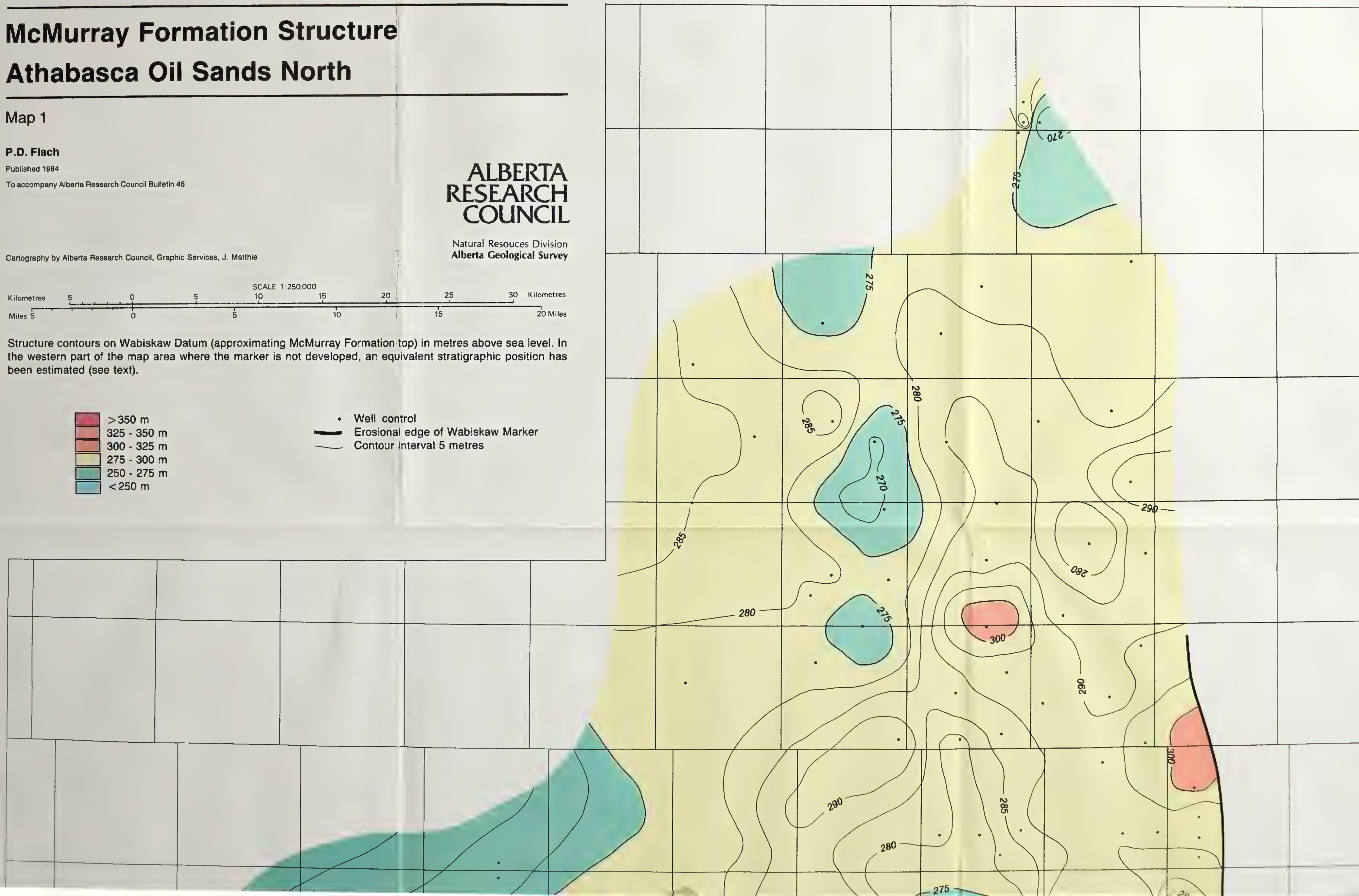
Kilometres 5 0 5 10 15 20 25 30 Kilometres

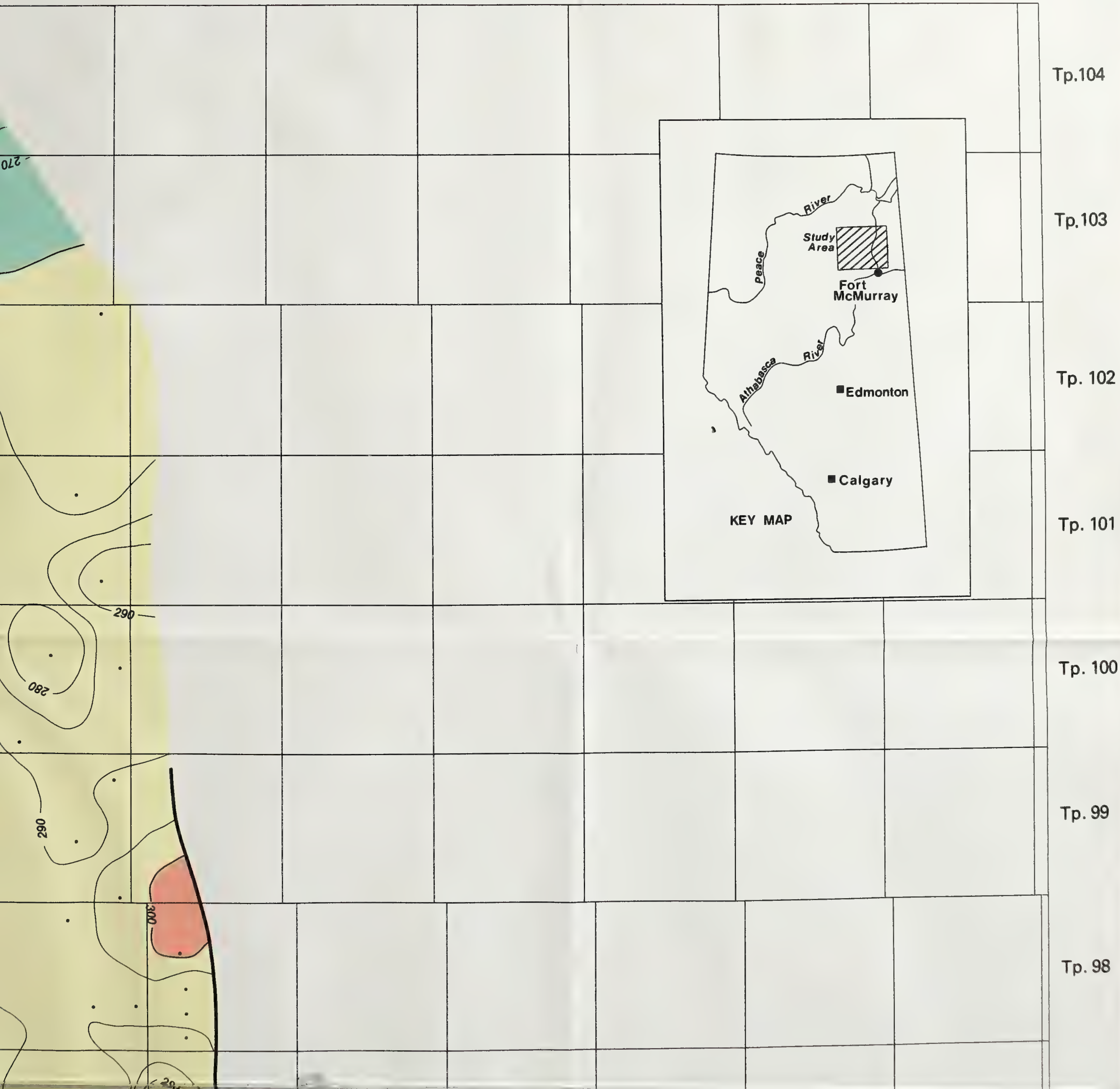
Miles 5 0 5 10 15 20 Miles

Structure contours on Wabiskaw Datum (approximating McMurray Formation top) in metres above sea level. In the western part of the map area where the marker is not developed, an equivalent stratigraphic position has been estimated (see text).

- >350 m
- 325 - 350 m
- 300 - 325 m
- 275 - 300 m
- 250 - 275 m
- <250 m

- • Well control
- Erosional edge of Wabiskaw Marker
- Contour interval 5 metres

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Tp. 102
Tp. 101
Tp. 100
Tp. 99
Tp. 98
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290
280
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300
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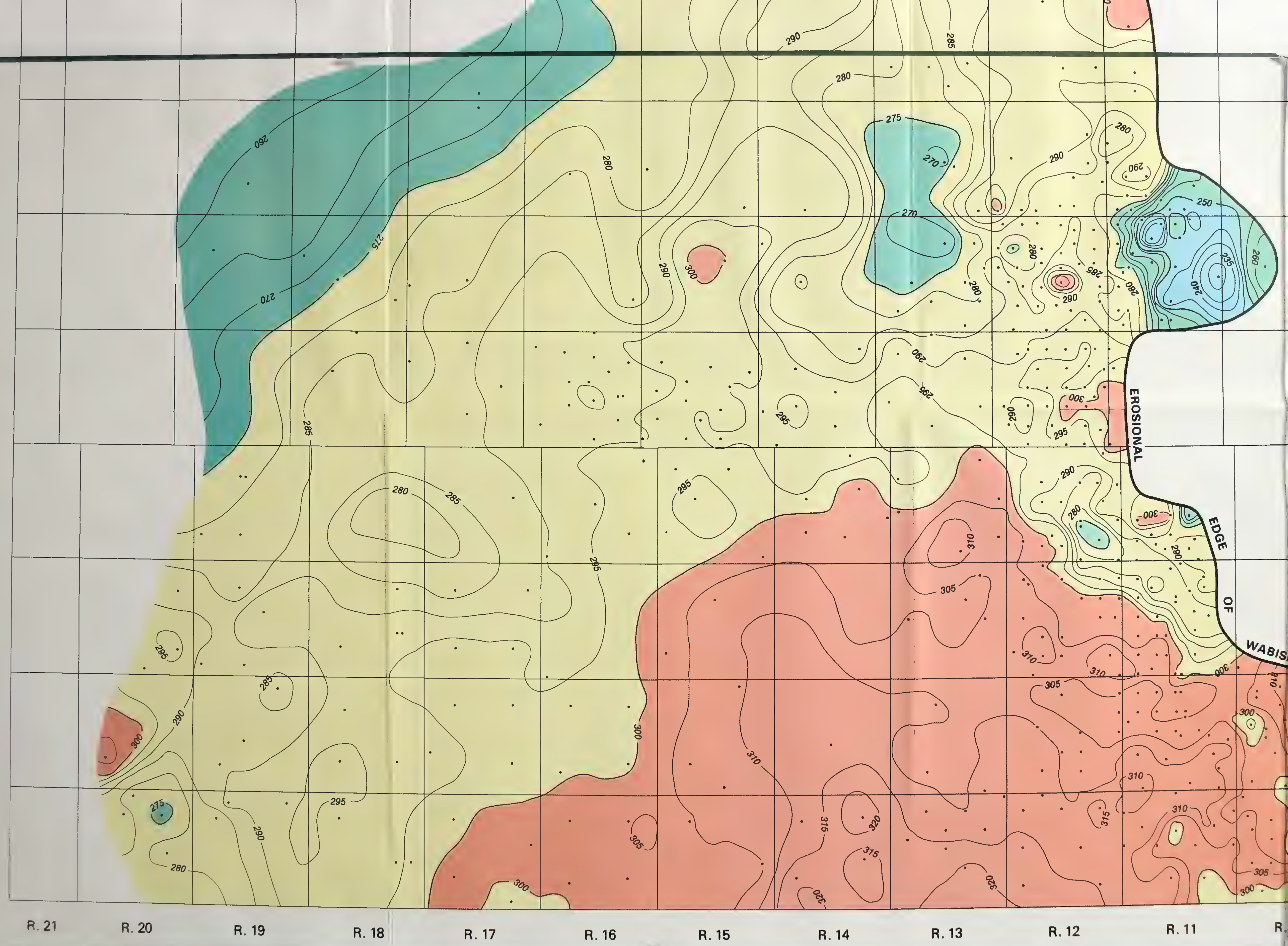
Peace
River
Study Area
Fort McMurray
Athabasca
River
Edmonton
Calgary


EROSIONAL
EDGE
OF
WABIS
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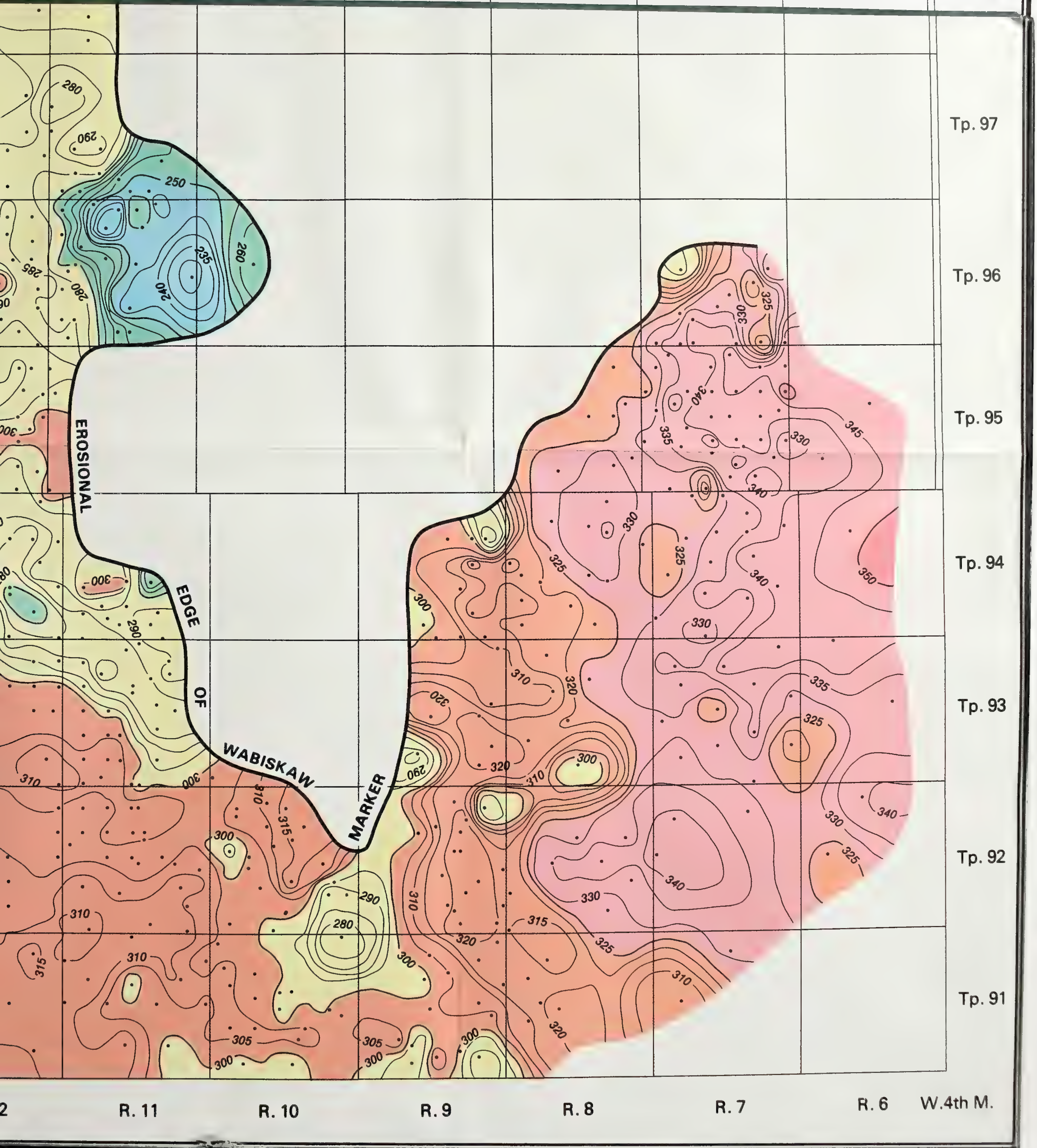
R. 19
R. 18
R. 17
R. 16
R. 15
R. 14
R. 13
R. 12
R. 11
R.


Tp. 97
Tp. 96
Tp. 95
Tp. 94
Tp. 93
Tp. 92
Tp. 91
EROSIONAL EDGE OF WABISKAW MARKER
R. 11
R. 10
R. 9
R. 8
R. 7
R. 6
W.4th M.

McMurray Formation Isopach
Athabasca Oil Sands North

Map 2

P.D. Flach

Published 1984

To accompany Alberta Research Council Bulletin 46

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RESEARCH
COUNCIL

Natural Resouces Division
Alberta Geological Survey

Cartography by Alberta Research Council, Graphic Services, J. Matthie

SCALE 1:250,000

Kilometres 5 0 5 10 15 20 25 30 Kilometres

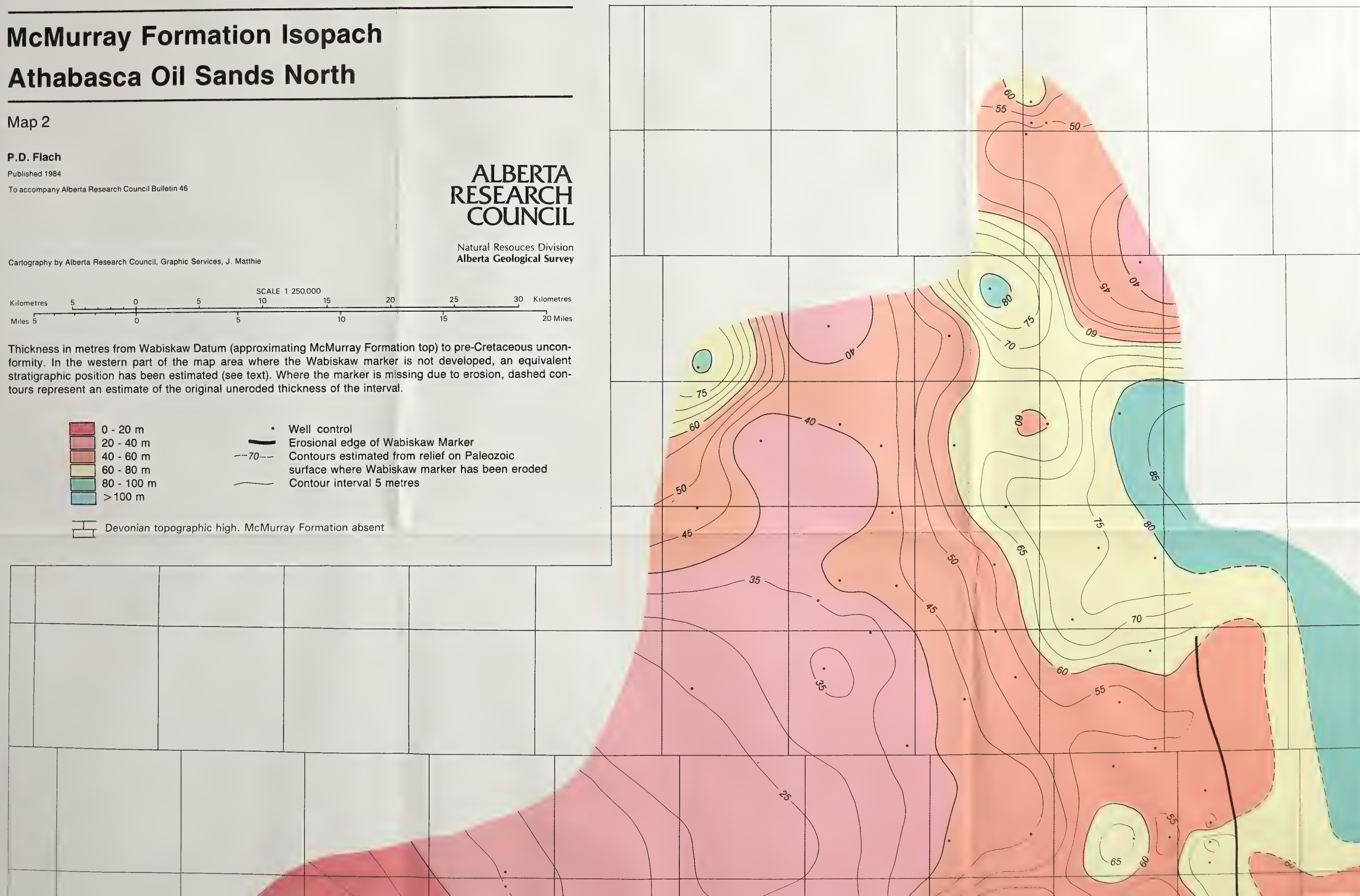
Miles 5 0 5 10 15 20 Miles

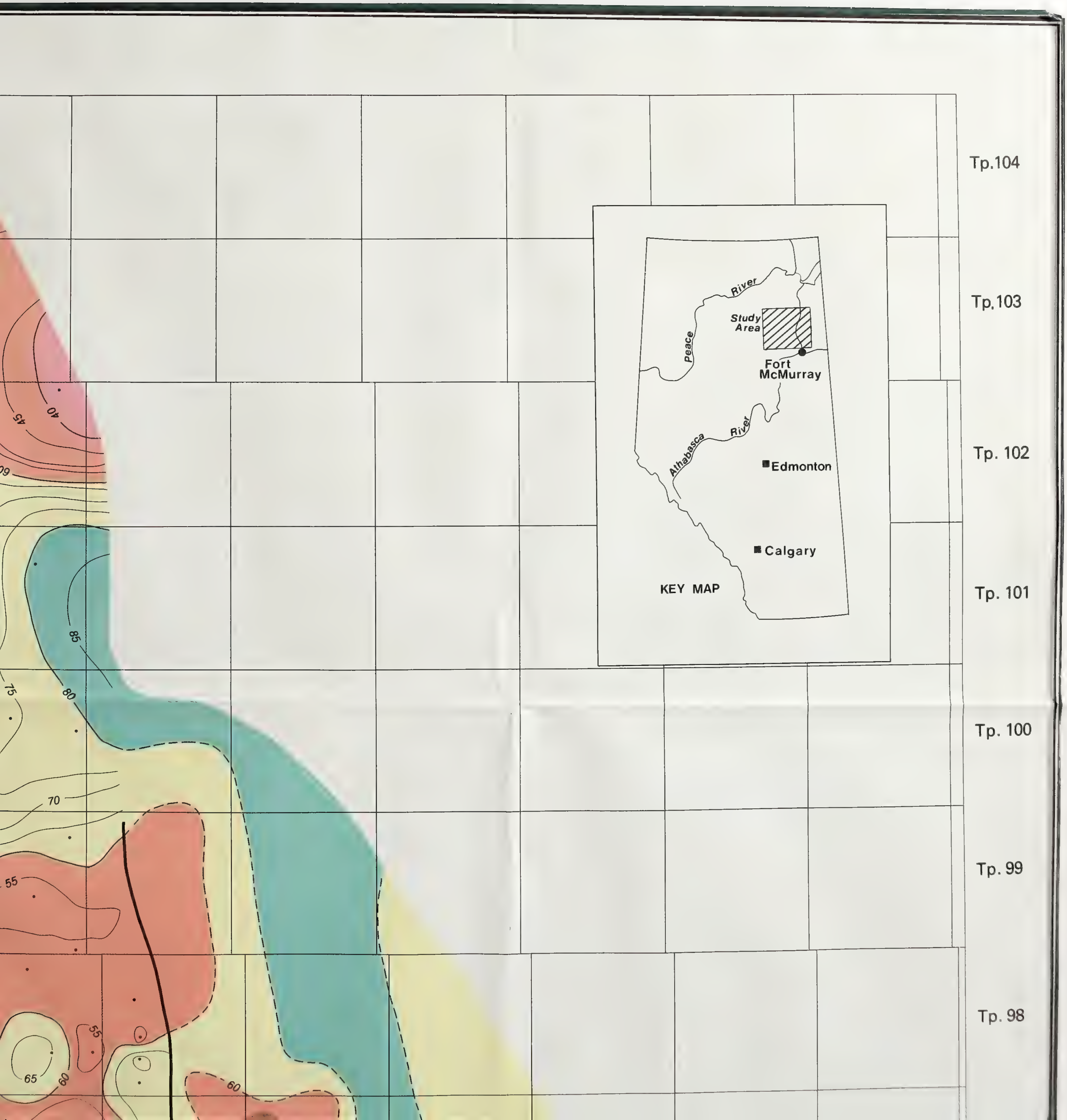
Thickness in metres from Wabiskaw Datum (approximating McMurray Formation top) to pre-Cretaceous unconformity. In the western part of the map area where the Wabiskaw marker is not developed, an equivalent stratigraphic position has been estimated (see text). Where the marker is missing due to erosion, dashed contours represent an estimate of the original uneroded thickness of the interval.

- 0 - 20 m
- 20 - 40 m
- 40 - 60 m
- 60 - 80 m
- 80 - 100 m
- >100 m

- Well control
- Erosional edge of Wabiskaw Marker
- --70-- Contours estimated from relief on Paleozoic surface where Wabiskaw marker has been eroded
- Contour interval 5 metres

Devonian topographic high. McMurray Formation absent





Tp.104
Tp.103
Tp. 102
Tp. 101
Tp. 100
Tp. 99
Tp. 98
KEY MAP
Peace
River
Study
Area
Fort
McMurray
Athabasca
River
Edmonton
Calgary
40
45
60
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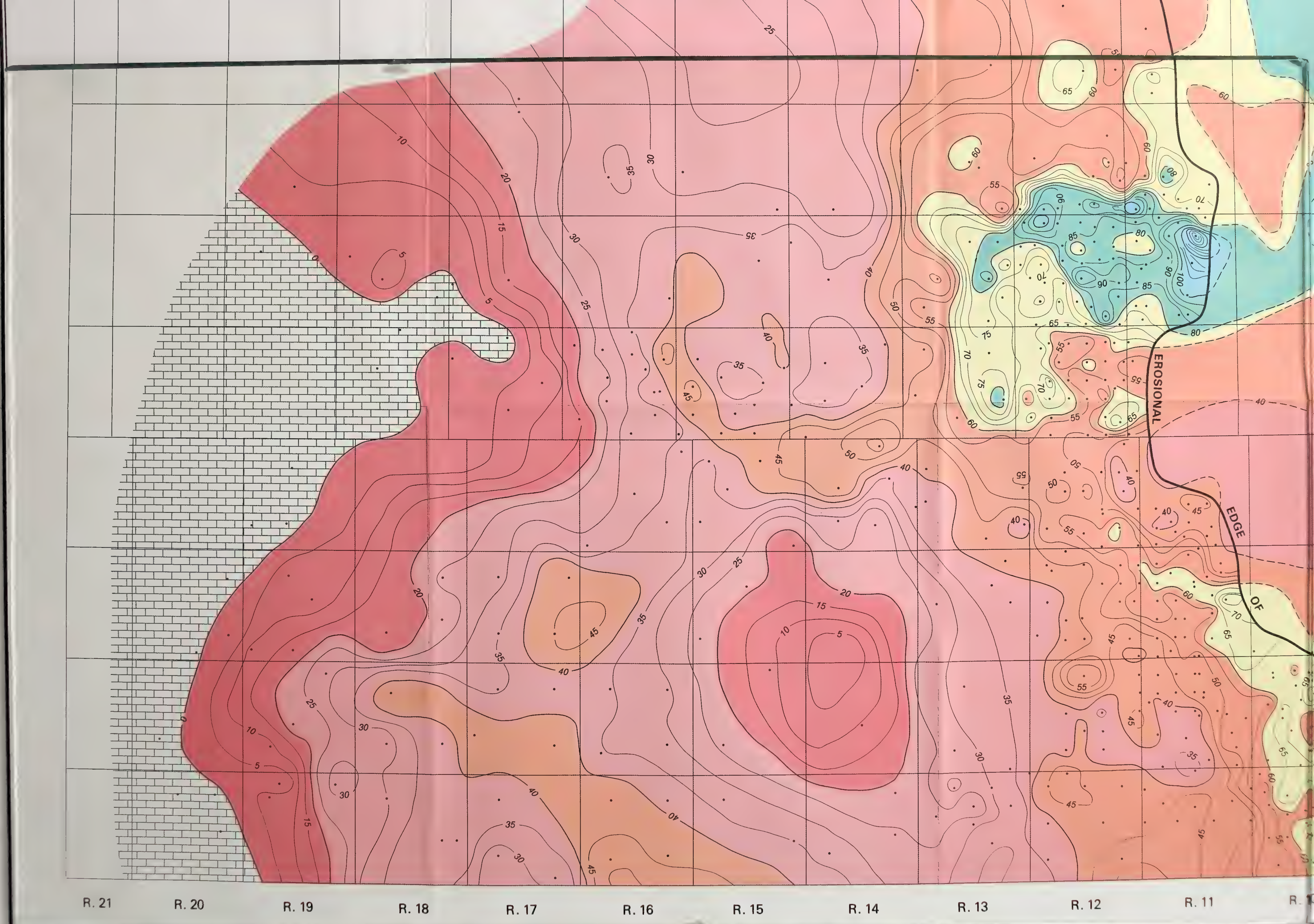
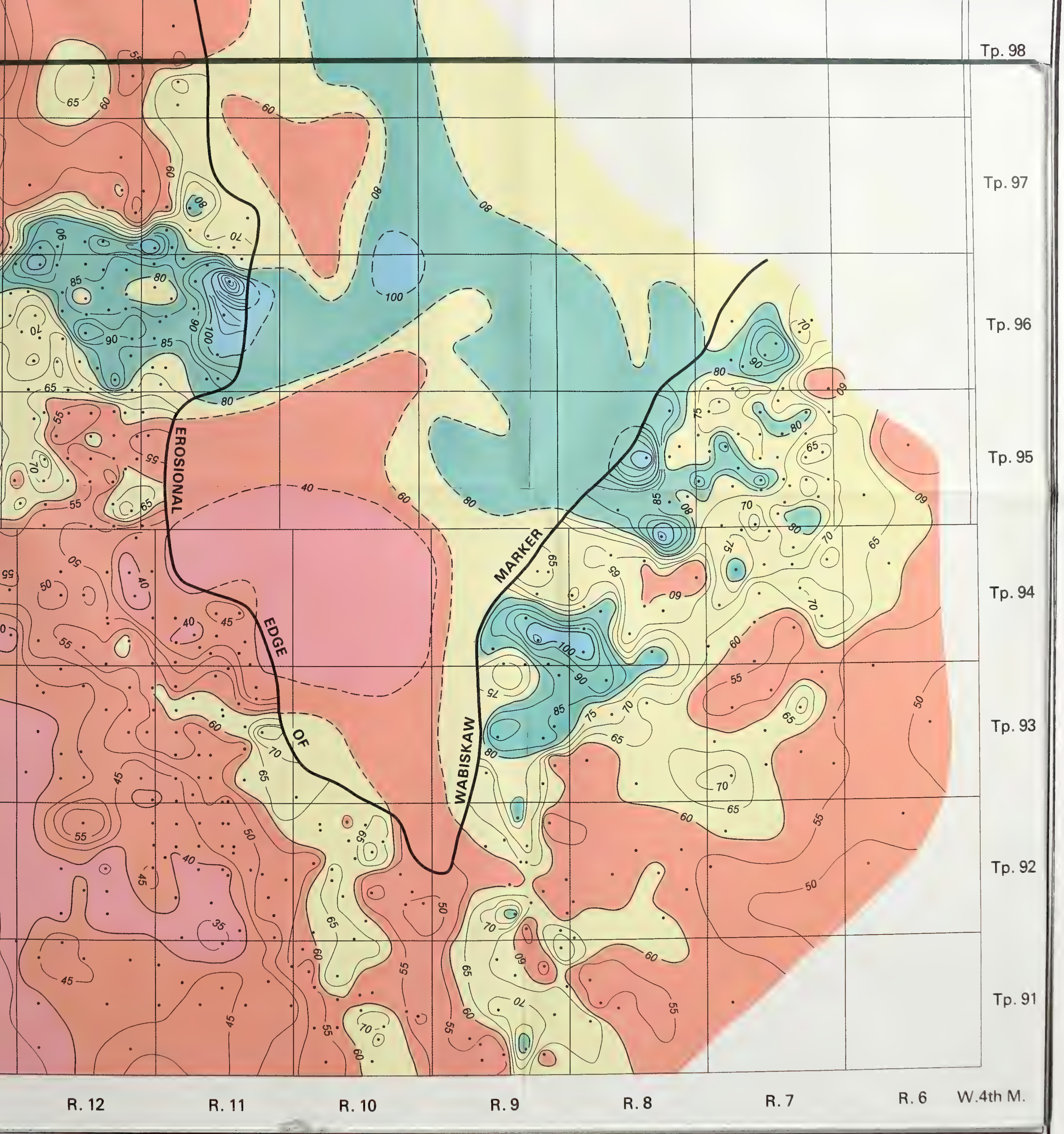
80
75
70
55
55
65
60
60


EROSIONAL
EDGE
OF
R. 21
R. 20
R. 19
R. 18
R. 17
R. 16
R. 15
R. 14
R. 13
R. 12
R. 11


EROSIONAL EDGE OF WABISKAW MARKER
Tp. 98
Tp. 97
Tp. 96
Tp. 95
Tp. 94
Tp. 93
Tp. 92
Tp. 91
R. 12
R. 11
R. 10
R. 9
R. 8
R. 7
R. 6
W.4th M.

Unconformity Structure
Athabasca Oil Sands North

Map 3

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SCALE 1:250,000

Kilometres 5 0 5 10 15 20 25 30 Kilometres

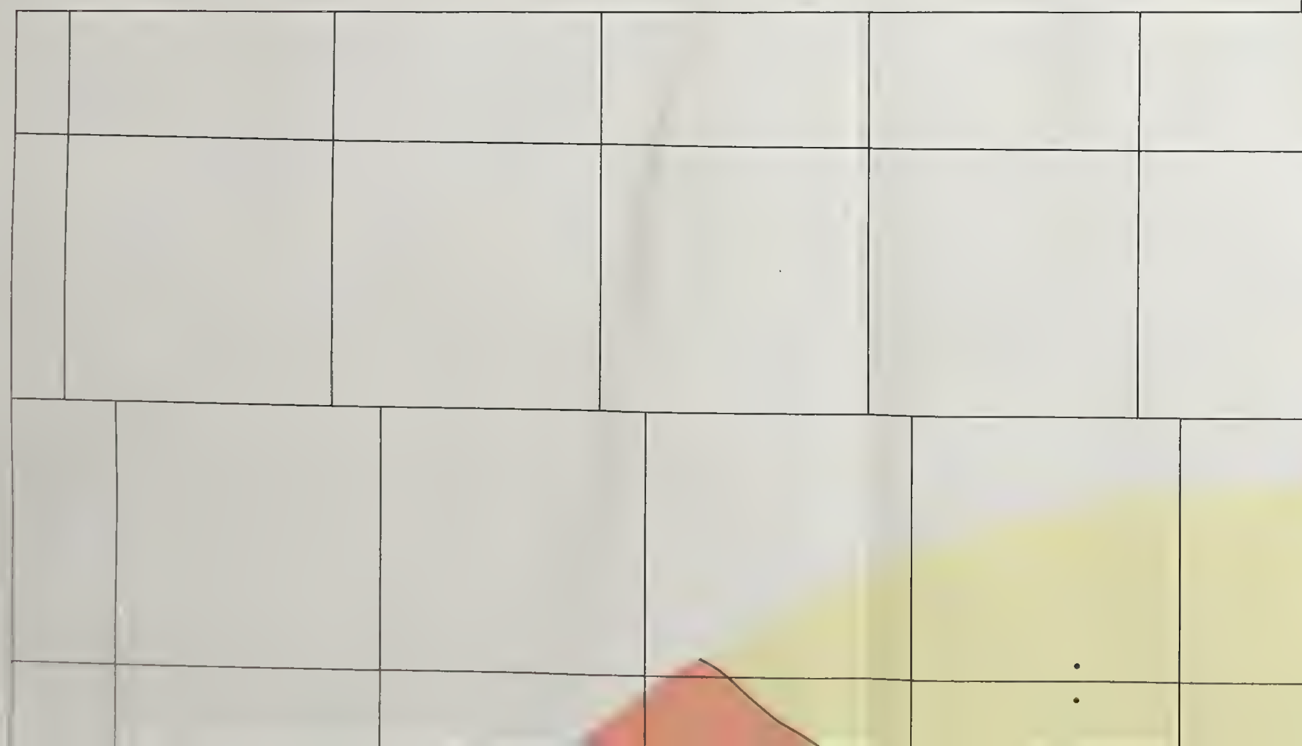
Miles 5 0 5 10 15 20 Miles

Structure contours on the pre-Cretaceous unconformity, in metres above sea level.

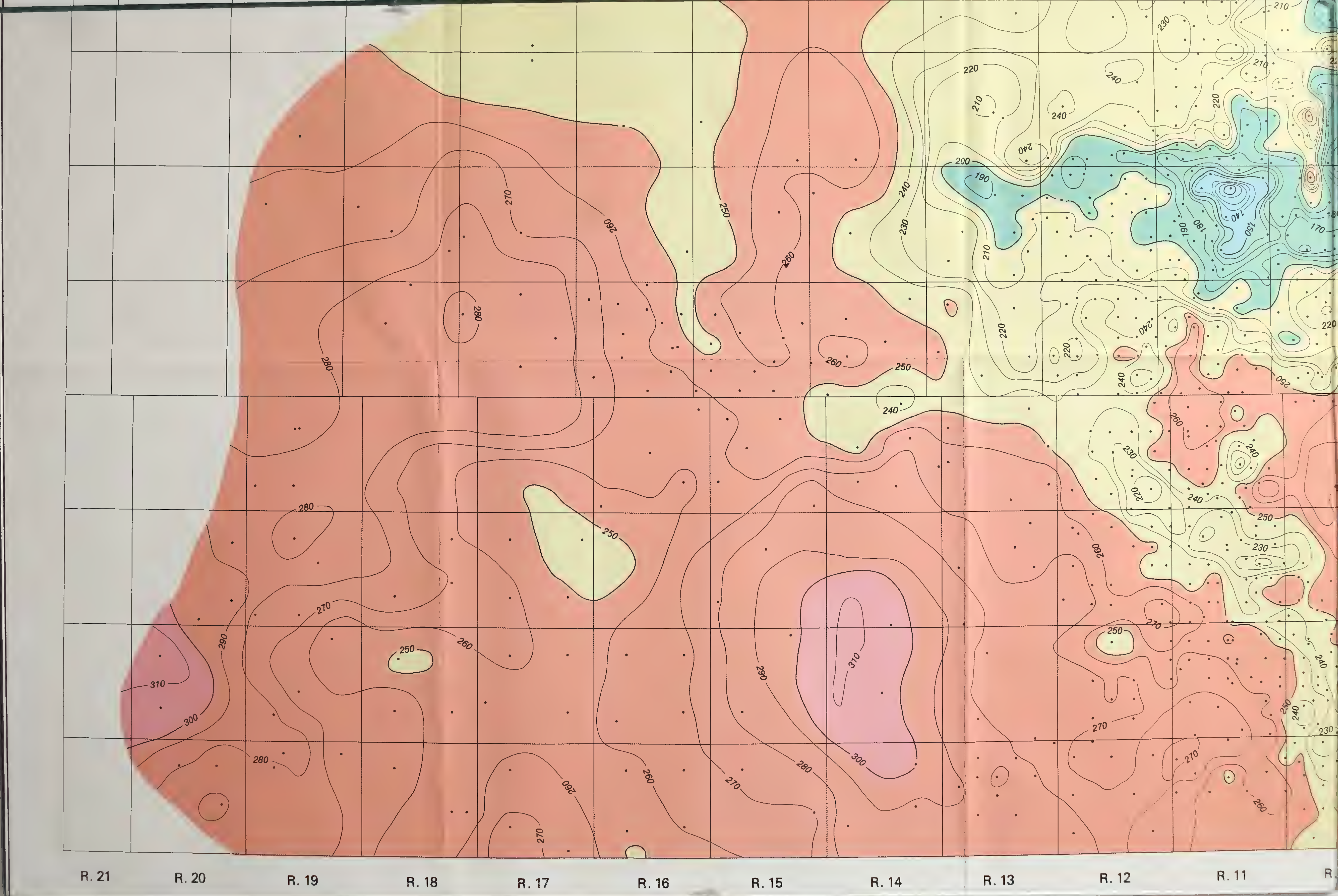
- >300 m
- 250 - 300 m
- 200 - 250 m
- 150 - 200 m
- <150 m

• Well control

Contour interval 10 metres




Tp.104
Tp.103
Tp. 102
Tp. 101
Tp. 100
Tp. 99
Tp. 98
Tp. 97
KEY MAP
Peace
River
Study Area
Fort McMurray
Athabasca
River
Edmonton
Calgary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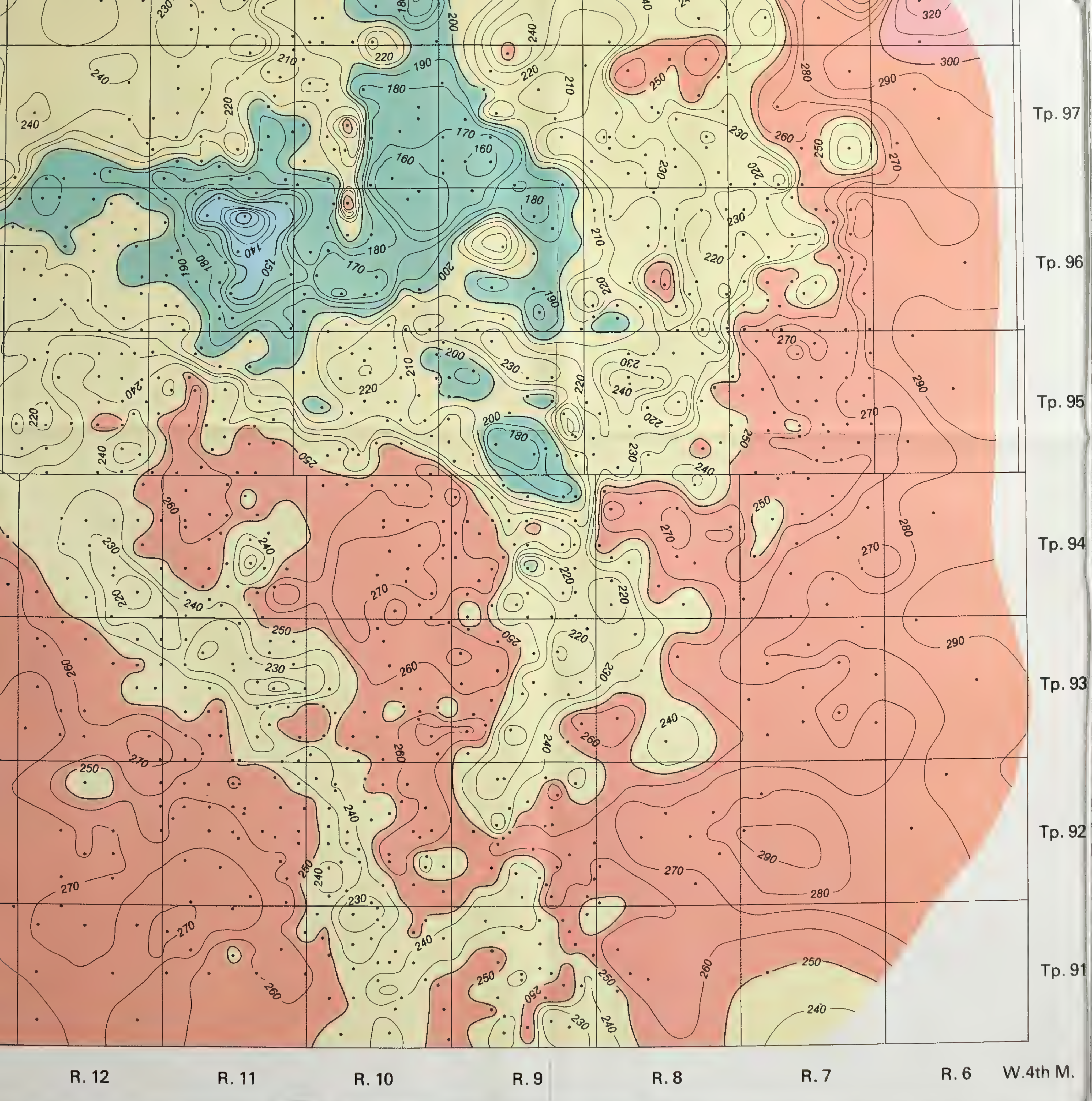
R. 12
R. 11



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Tp. 95
Tp. 94
Tp. 93
Tp. 92
Tp. 91
R. 12
R. 11
R. 10
R. 9
R. 8
R. 7
R. 6
W.4th M.

Sand Thickness
Athabasca Oil Sands North

Map 4

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SCALE 1:250,000

Kilometres 5 0 5 10 15 20 25 30 Kilometres

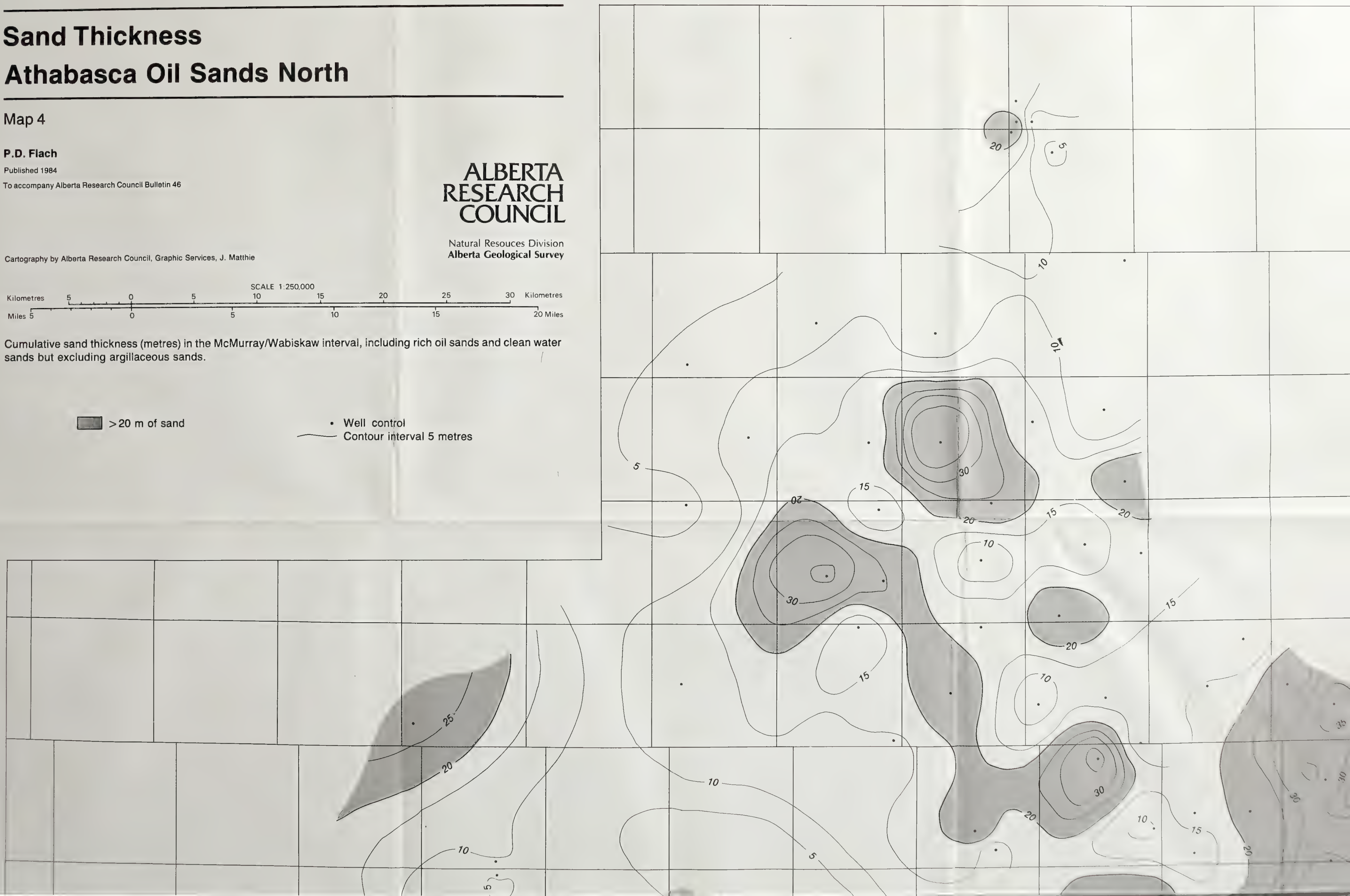
Miles 5 0 5 10 15 20 Miles

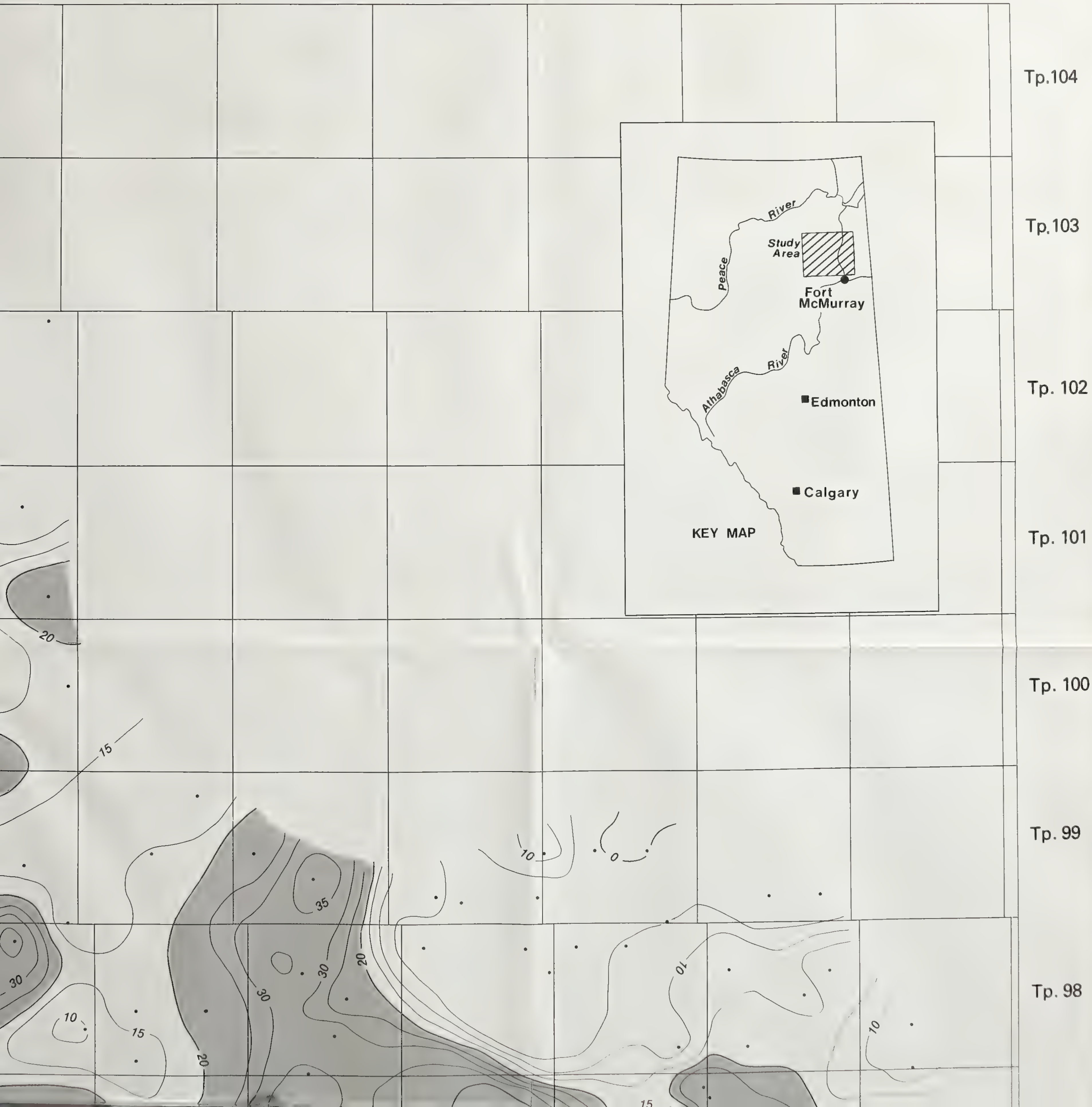
Cumulative sand thickness (metres) in the McMurray/Wabiskaw interval, including rich oil sands and clean water sands but excluding argillaceous sands.

>20 m of sand

• Well control

Contour interval 5 metres

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Tp.103
Tp. 102
Tp. 101
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Tp. 99
Tp. 98
River
Peace
Study Area
Fort McMurray
Athabasca
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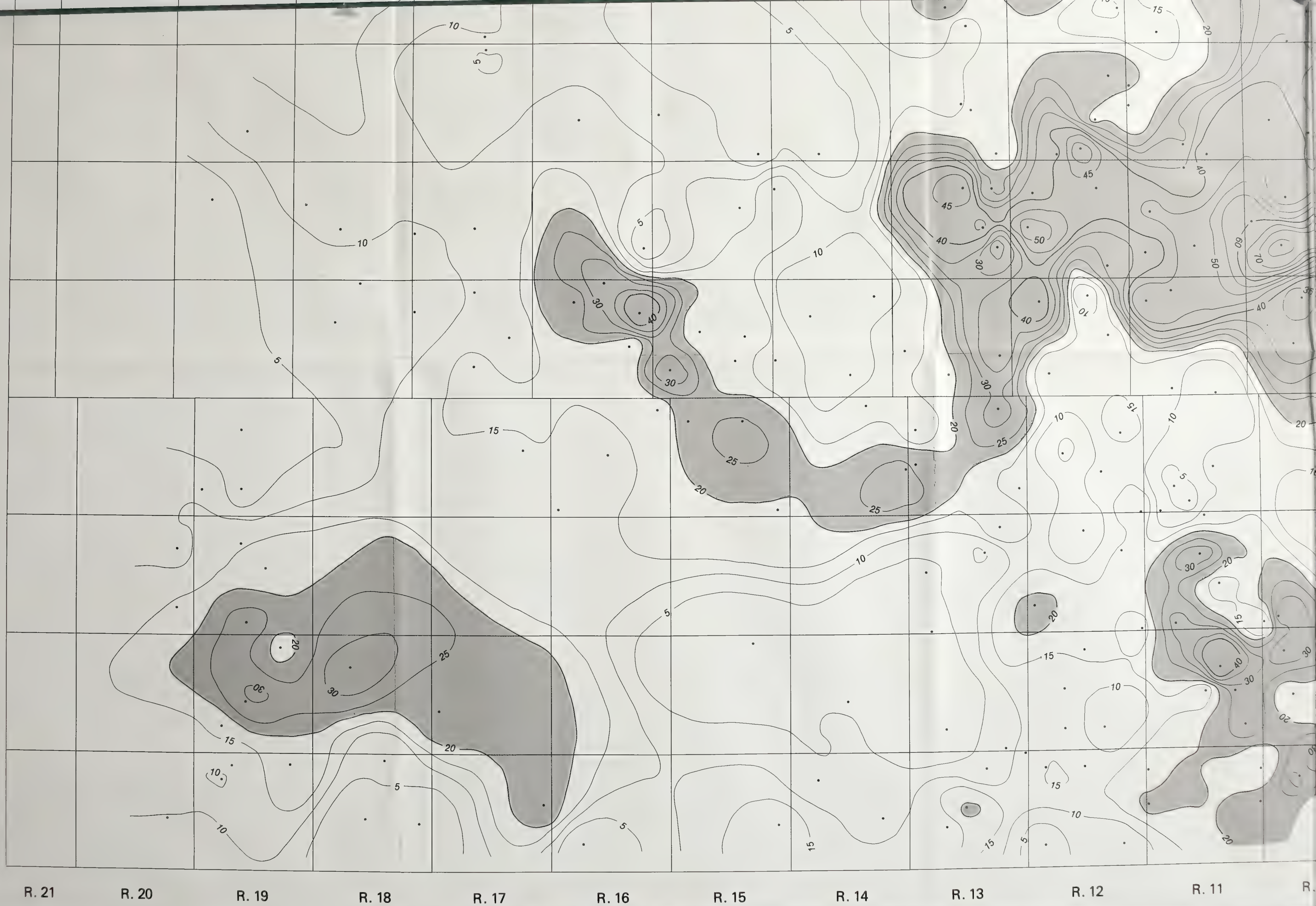
15
20
10
10
15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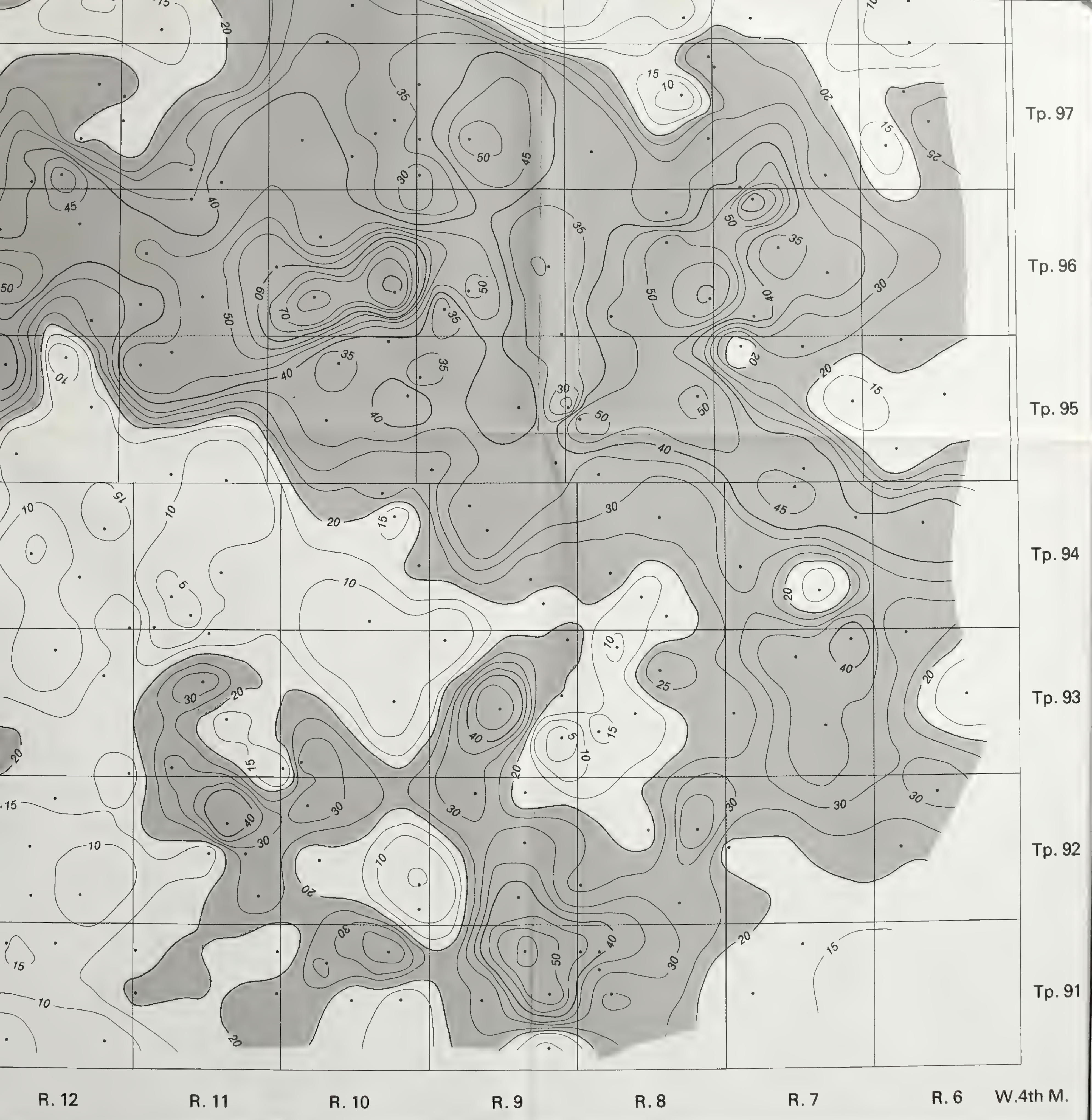
R. 15
R. 14
R. 13
R. 12
R. 11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Tp. 94
Tp. 93
Tp. 92
Tp. 91
R. 12
R. 11
R. 10
R. 9
R. 8
R. 7
R. 6
W.4th M.

Slice Maps of Sand Thickness
Athabasca Oil Sands North

Map 5

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Alberta Geological Survey

Cartography by Alberta Research Council, Graphic Services, A. Arseniuk.

Scale 1:1 000 000

Kilometres 10 5 0 10 20 30 40 50 60 Kilometres

Miles 10 5 0 10 20 30 40 Miles

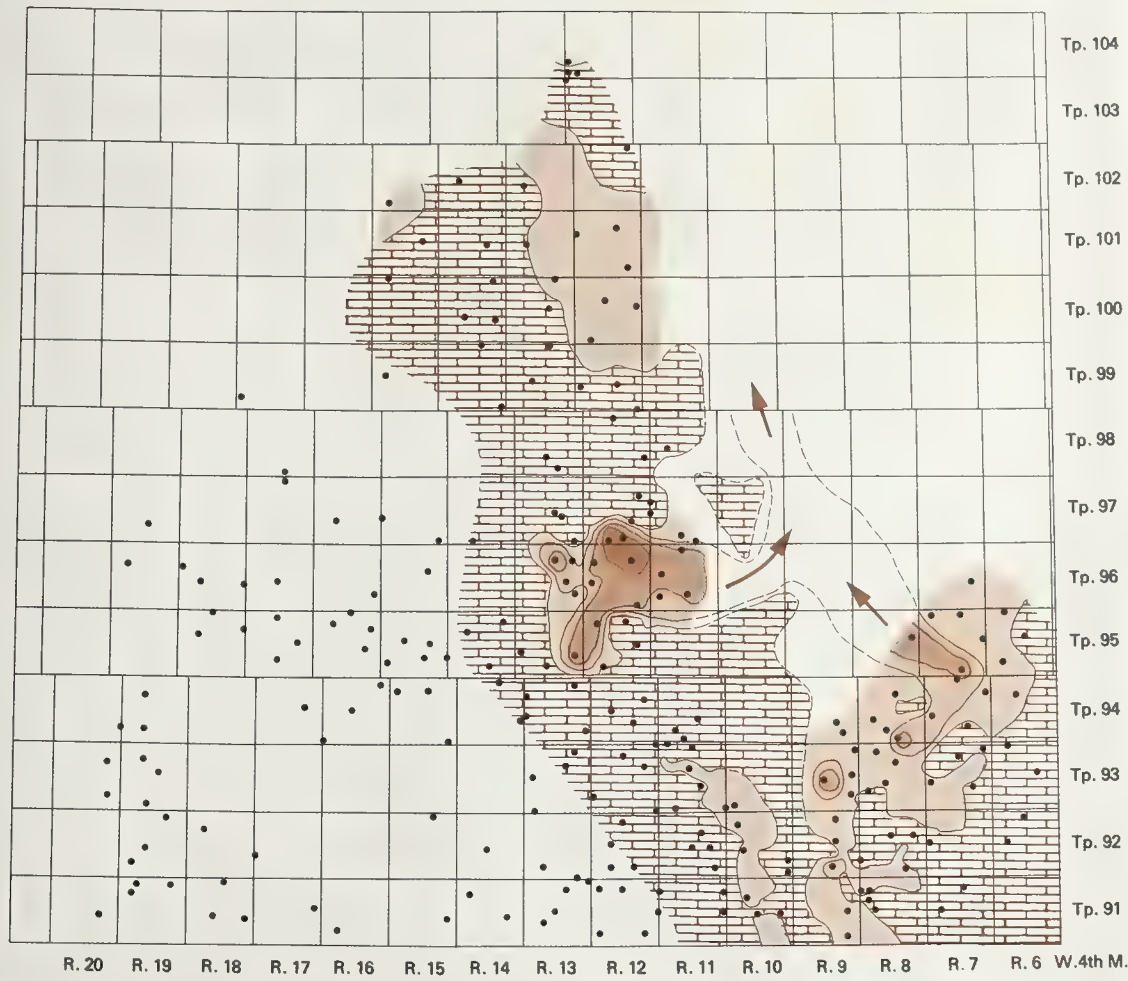
Cumulative sand thickness (metres) within successive 20 m slices of the McMurray/Wabiskaw interval, as measured from the Wabiskaw Datum.

A. 60 to 80 m below datum
B. 40 to 60 m below datum
C. 20 to 40 m below datum
D. 0 to 20 m below datum
E. 0 to 20 m above datum

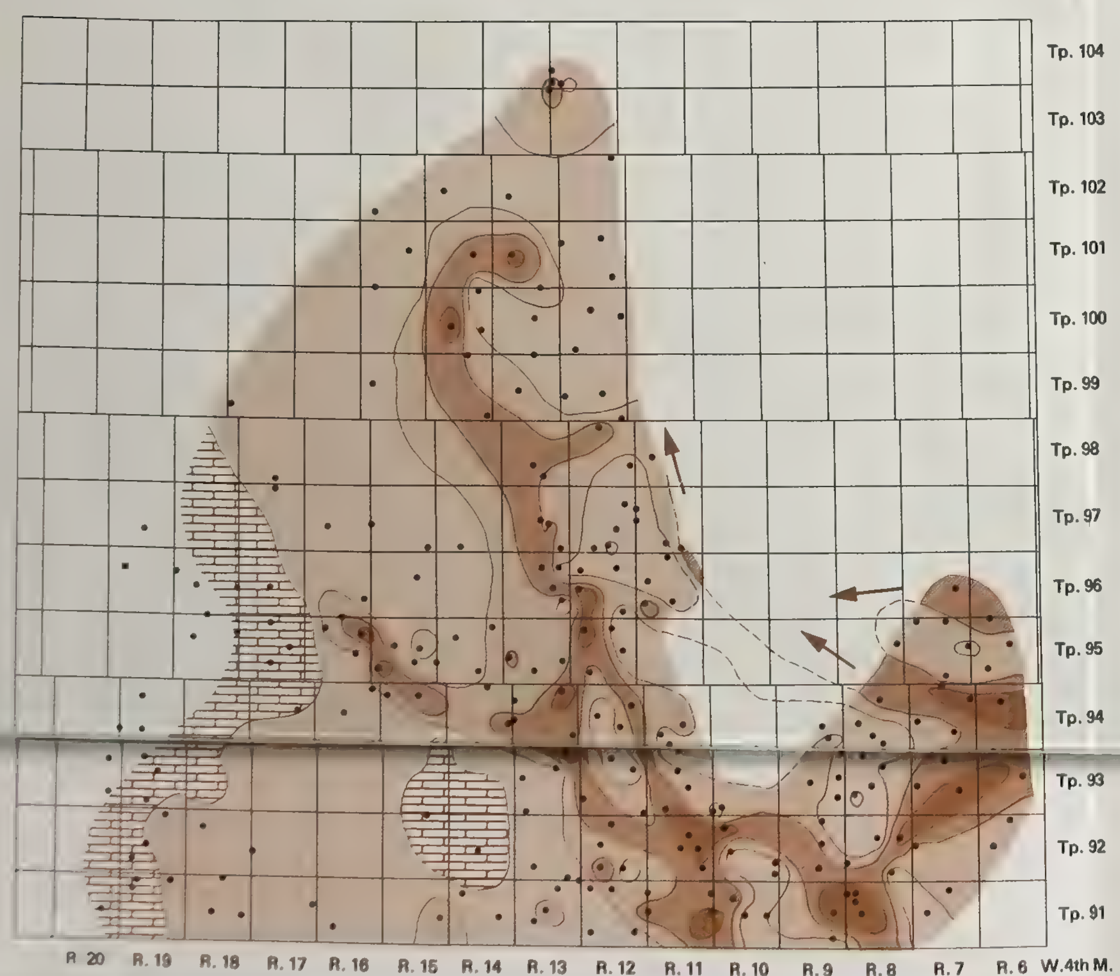
0 to 5 m sand
5 to 10 m sand
10 to 15 m sand
15 to 20 m sand
Devonian limestone to top of interval.
Inferred sand trend in area where datum is absent.
Inferred contours in area where datum is absent.

• Well Control. Data is missing in the northwest portion of each map because no wells have been drilled, in the northeast portion because the McMurray Formation is absent due to erosion, and in the central eastern area because the Wabiskaw datum from which the intervals are measured is eroded.

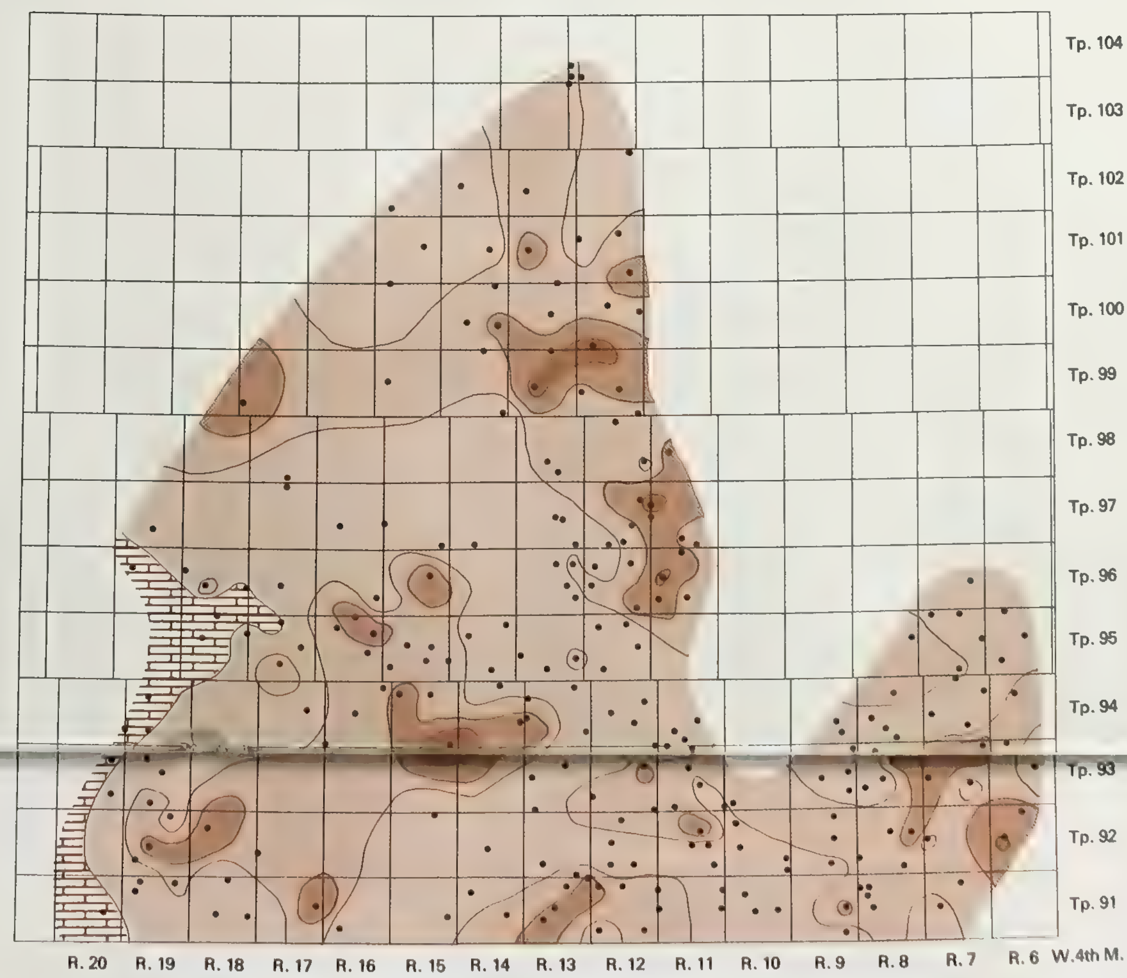
A. Sand thickness in the interval 60 to 80 m below datum, approximately representing the lower McMurray



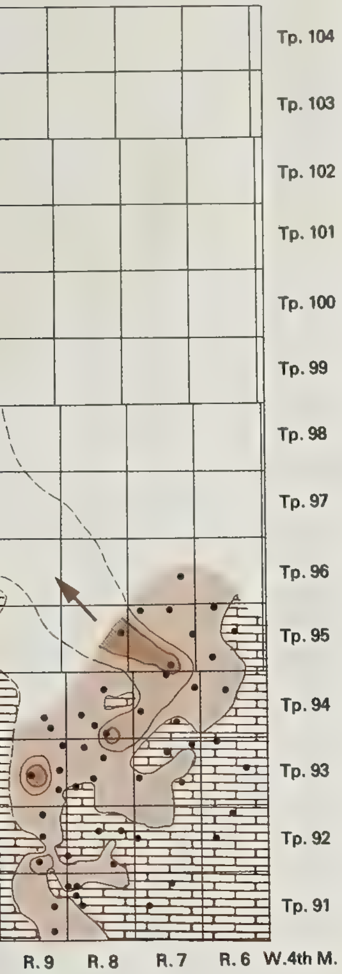
C. Sand thickness in the interval 20 to 40 m below datum, approximately representing the upper part of the middle McMurray.



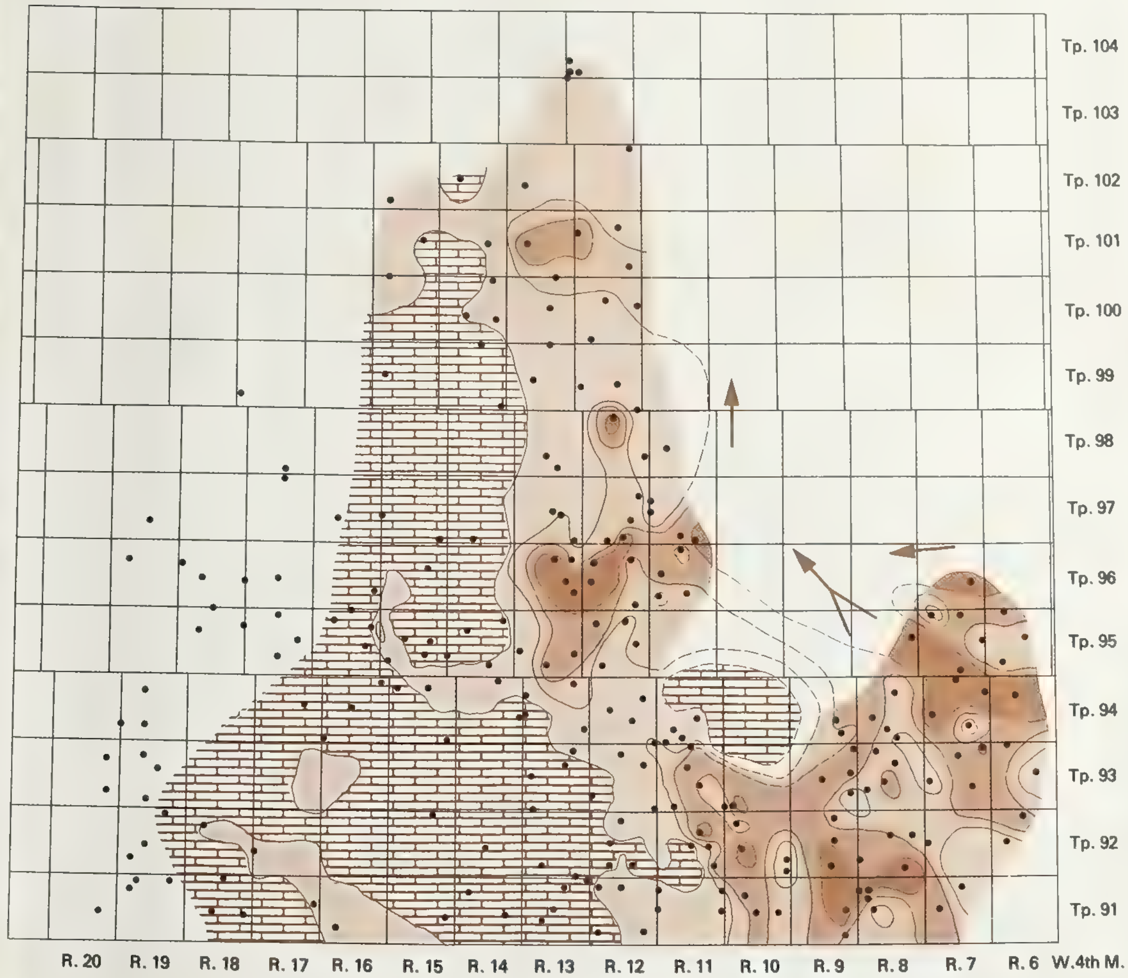
D. Sand thickness in the interval 0 to 20 m below datum, approximately representing the upper McMurray.



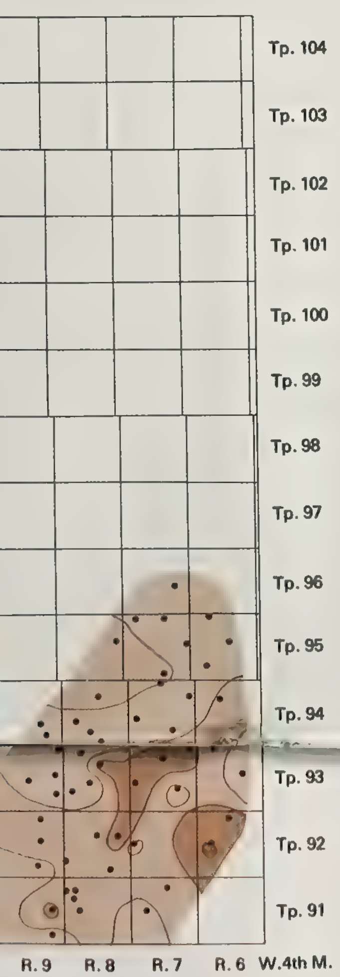
ximately representing



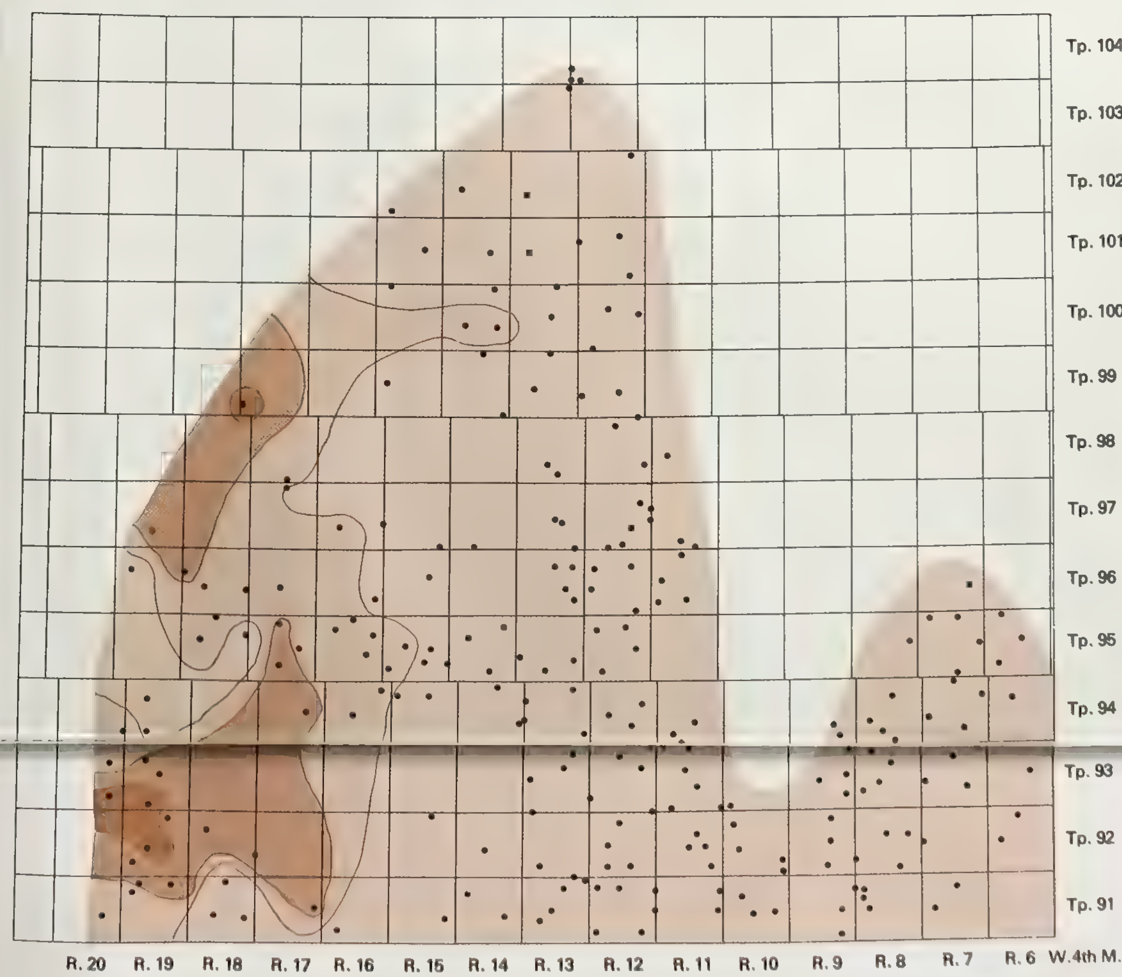
B. Sand thickness in the interval 40 to 60 m below datum, approximately representing the lower part of the middle McMurray.



mately representing



E. Sand thickness in the interval 0 to 20 m above datum, representing Clearwater Formation sands overlying the Wabiskaw datum.



Pay Thickness
Athabasca Oil Sands North

Map 6

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Alberta Geological Survey

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SCALE 1 250,000

Kilometres 5 0 5 10 15 20 25 30 Kilometres

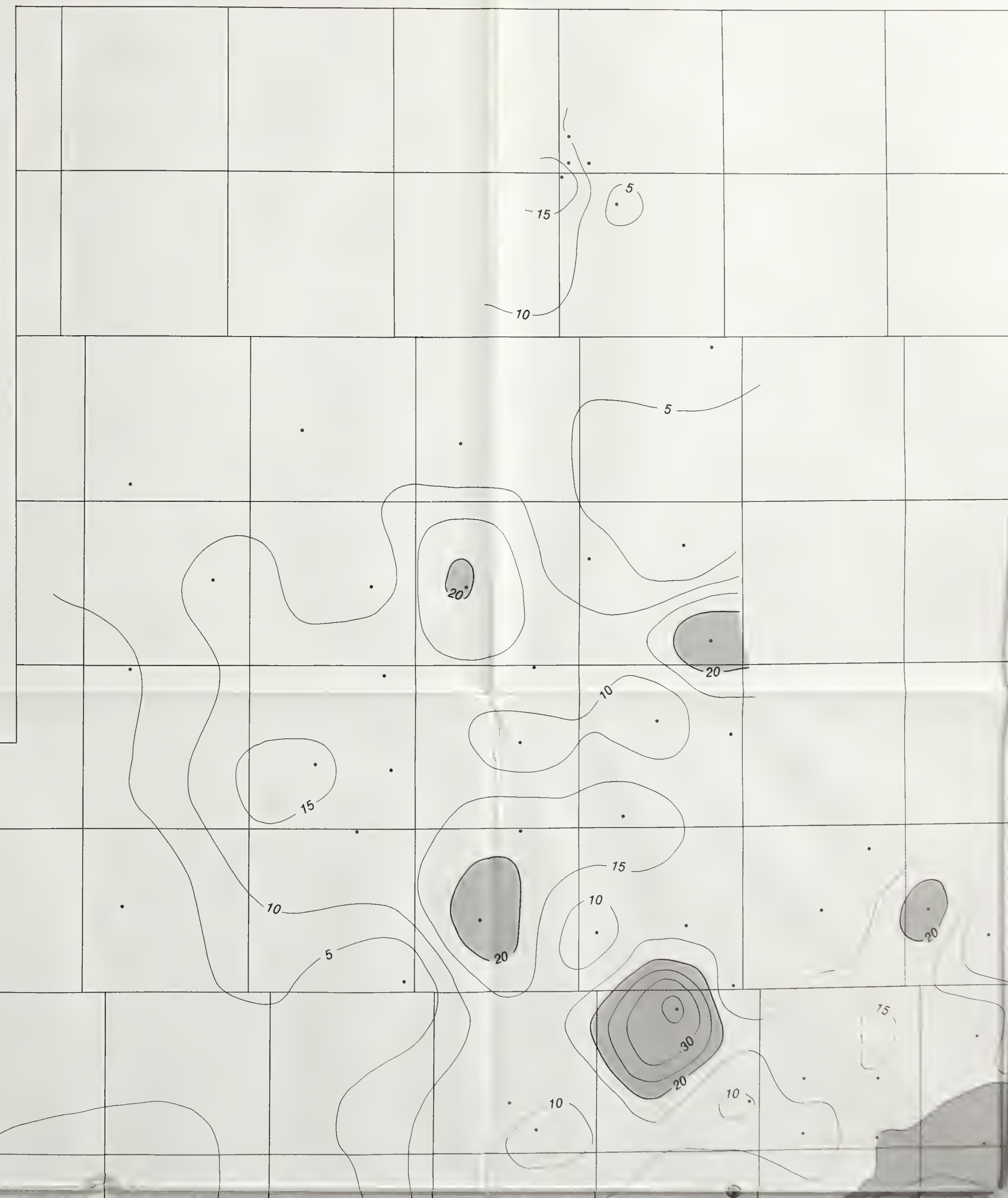
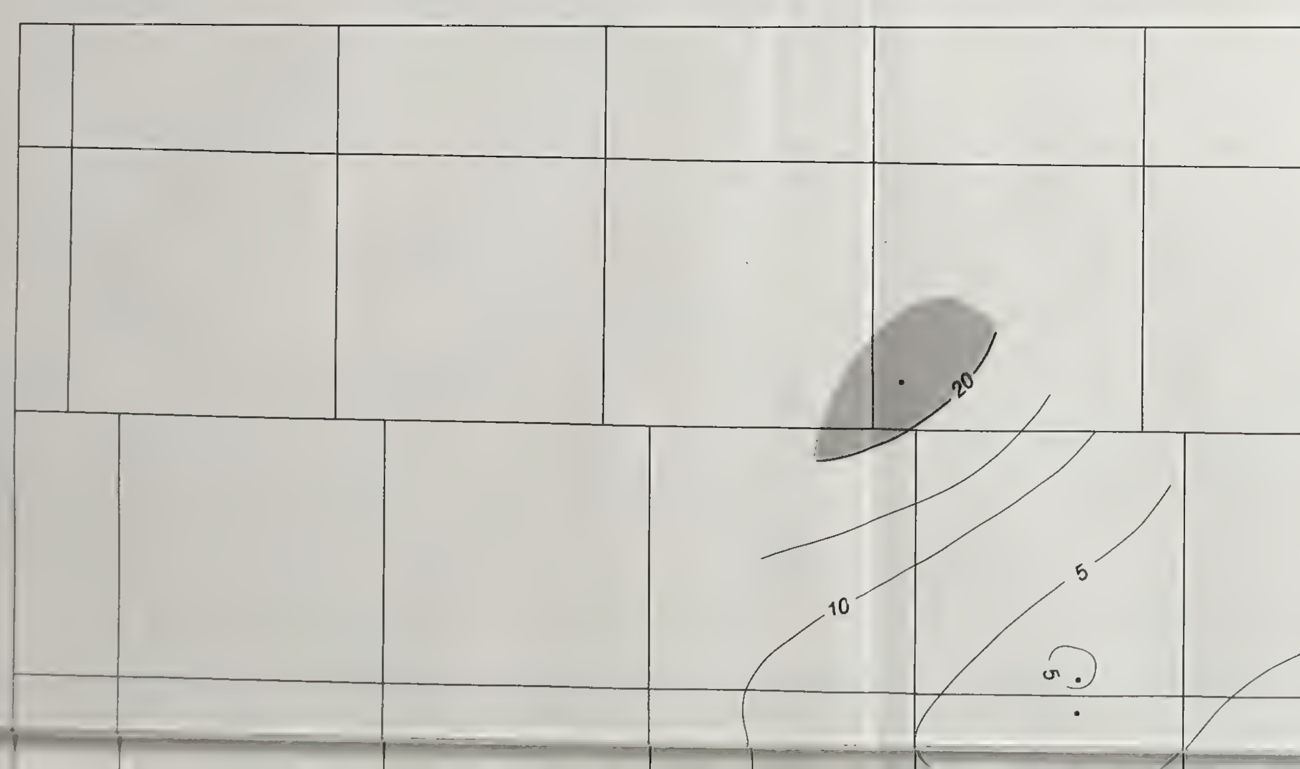
Miles 5 0 5 10 15 20 Miles

Cumulative thickness (metres) of rich oil sand (> 8% oil saturation by weight)

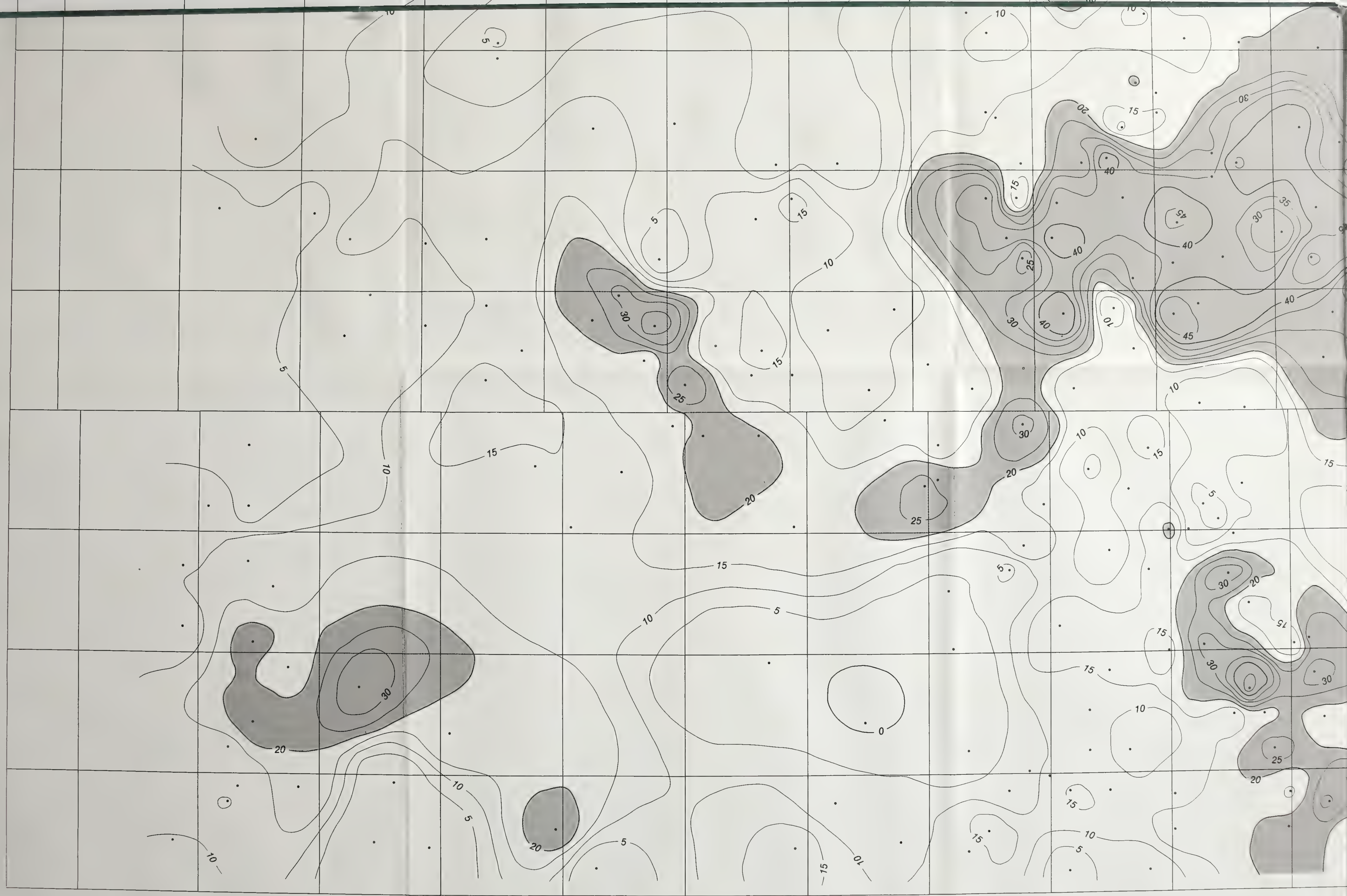
> 20 m of rich oil sand

• Well control

Contour interval 5 metres


Tp.104
Tp.103
Tp. 102
Tp. 101
Tp. 100
Tp. 99
Tp. 98
River
Study Area
Peace
Fort McMurray
Athabasca
River
Edmonton
Calgary
KEY MAP
5
5
20
10
15
10
20
30
20
10
10
15
10
5
0
0
0
5
15
10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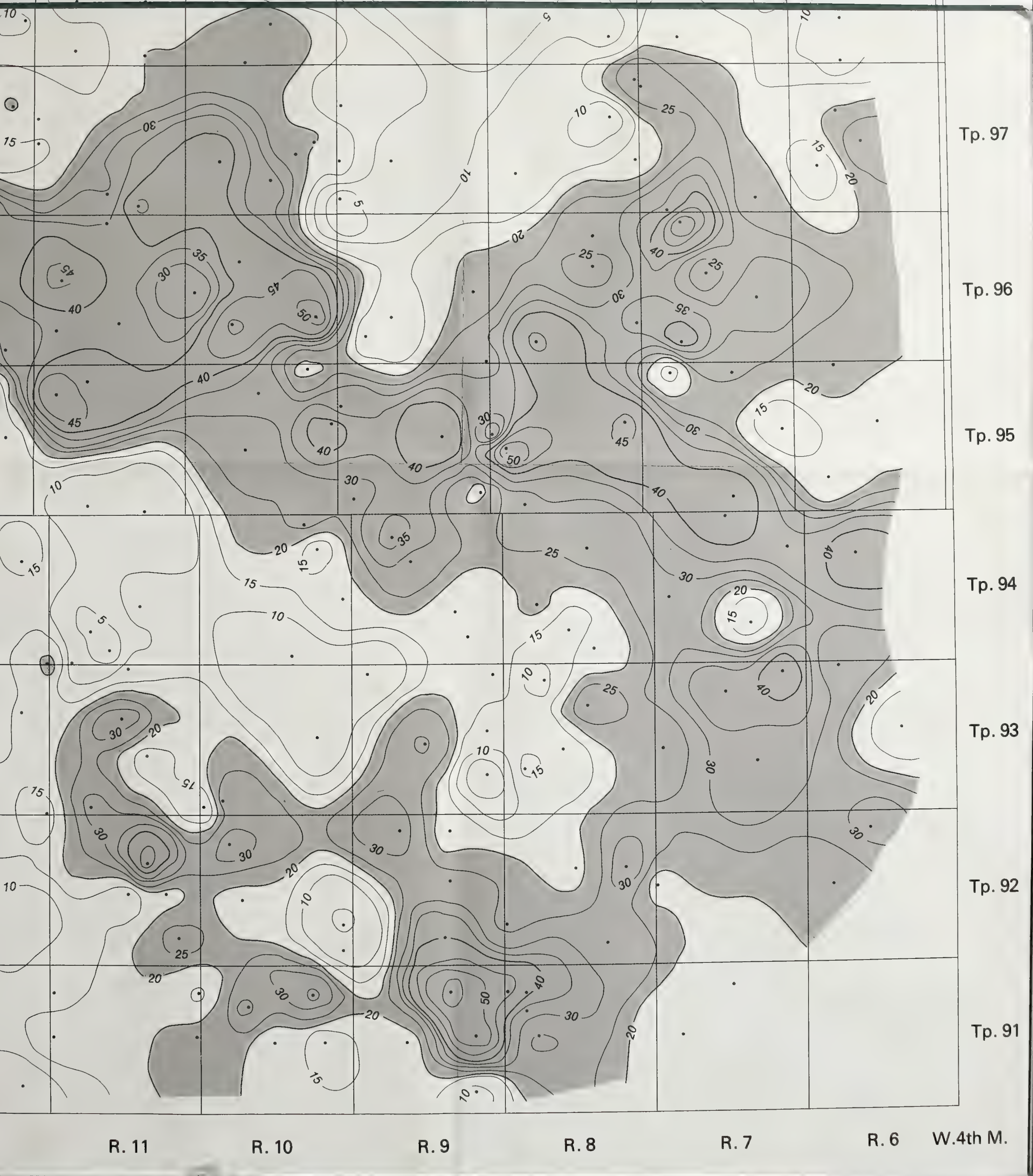
R. 13
R. 12
R. 11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Tp. 93
Tp. 92
Tp. 91
R. 11
R. 10
R. 9
R. 8
R. 7
R. 6
W.4th M.

Uninterrupted Pay Thickness
Athabasca Oil Sands North

Map 7

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SCALE 1:250,000

Kilometres 5 0 5 10 15 20 25 30 Kilometres

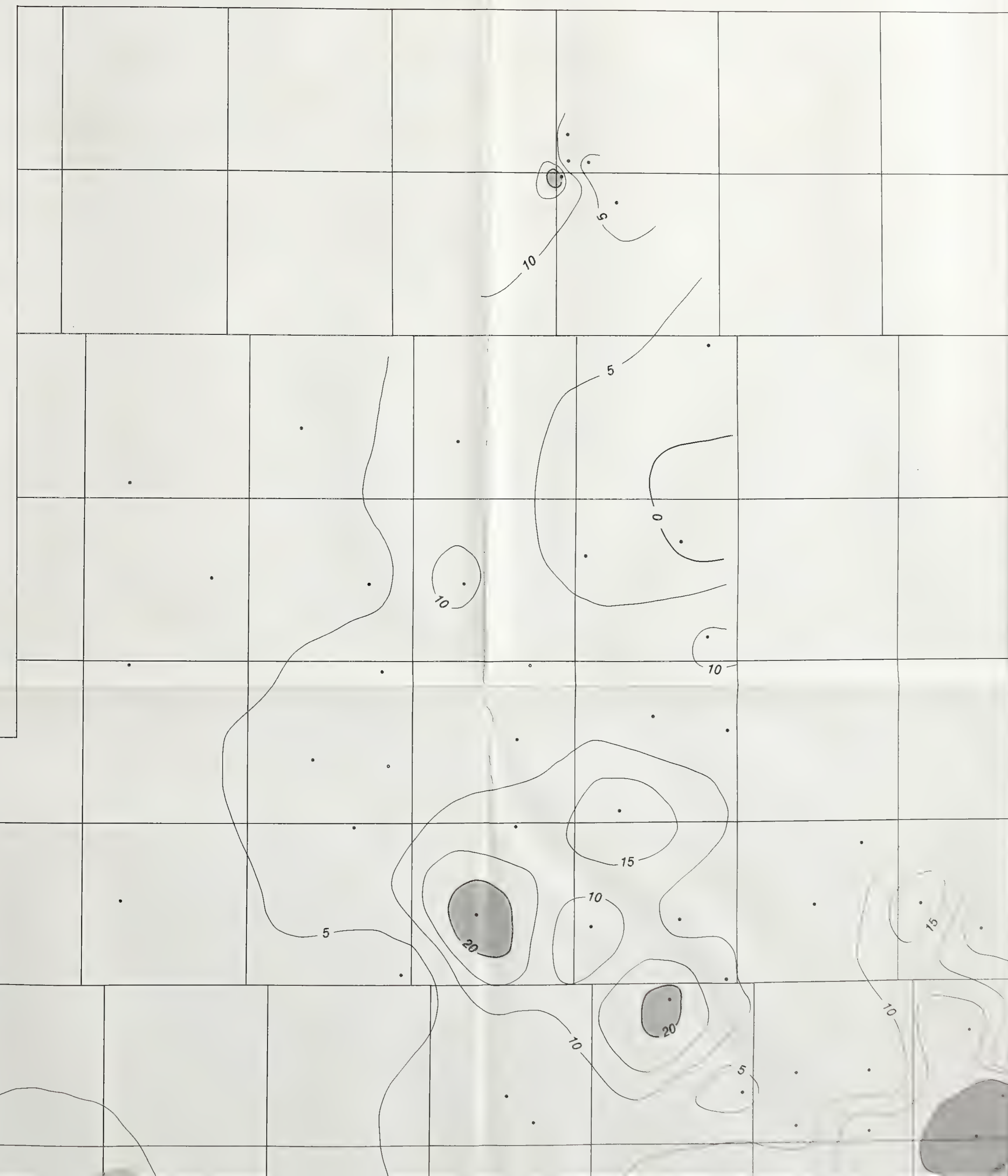
Miles 5 0 5 10 15 20 Miles

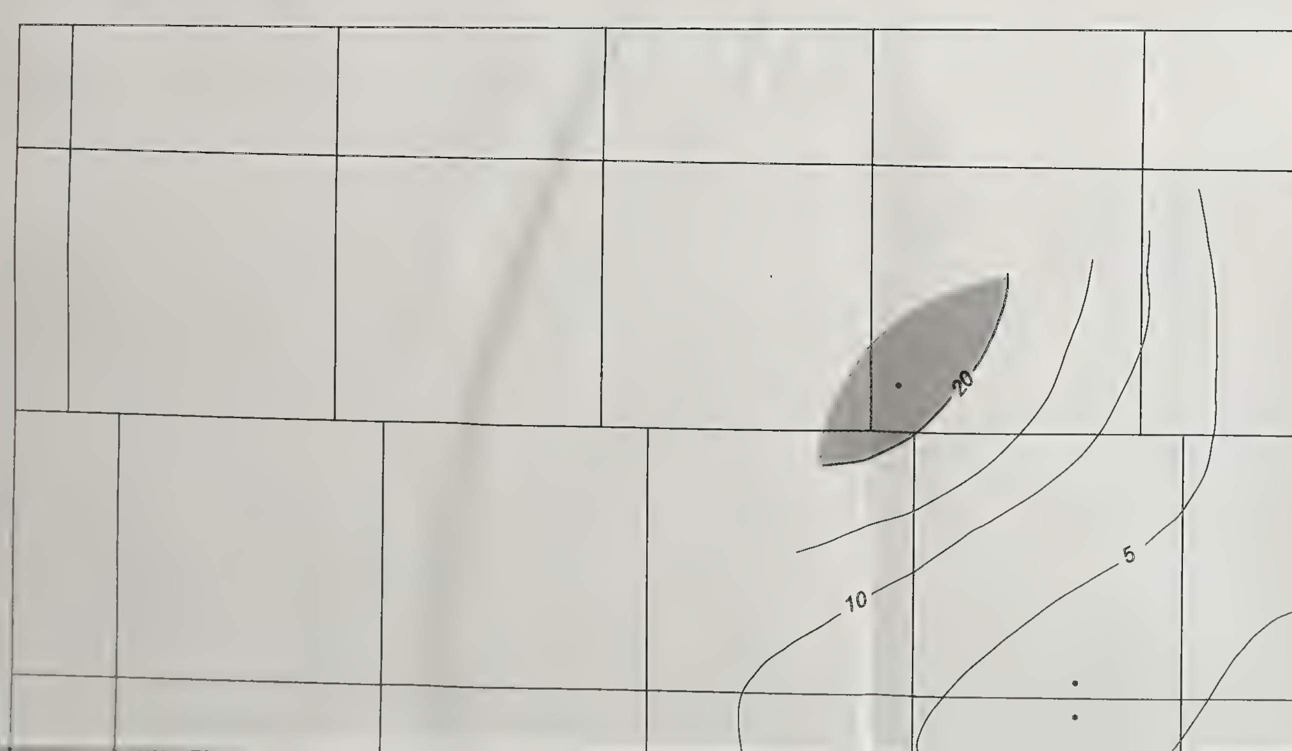
Maximum thickness (metres) of rich oil sand (>8 % oil saturation by weight), with no internal breaks of non-pay thicker than 3 m.

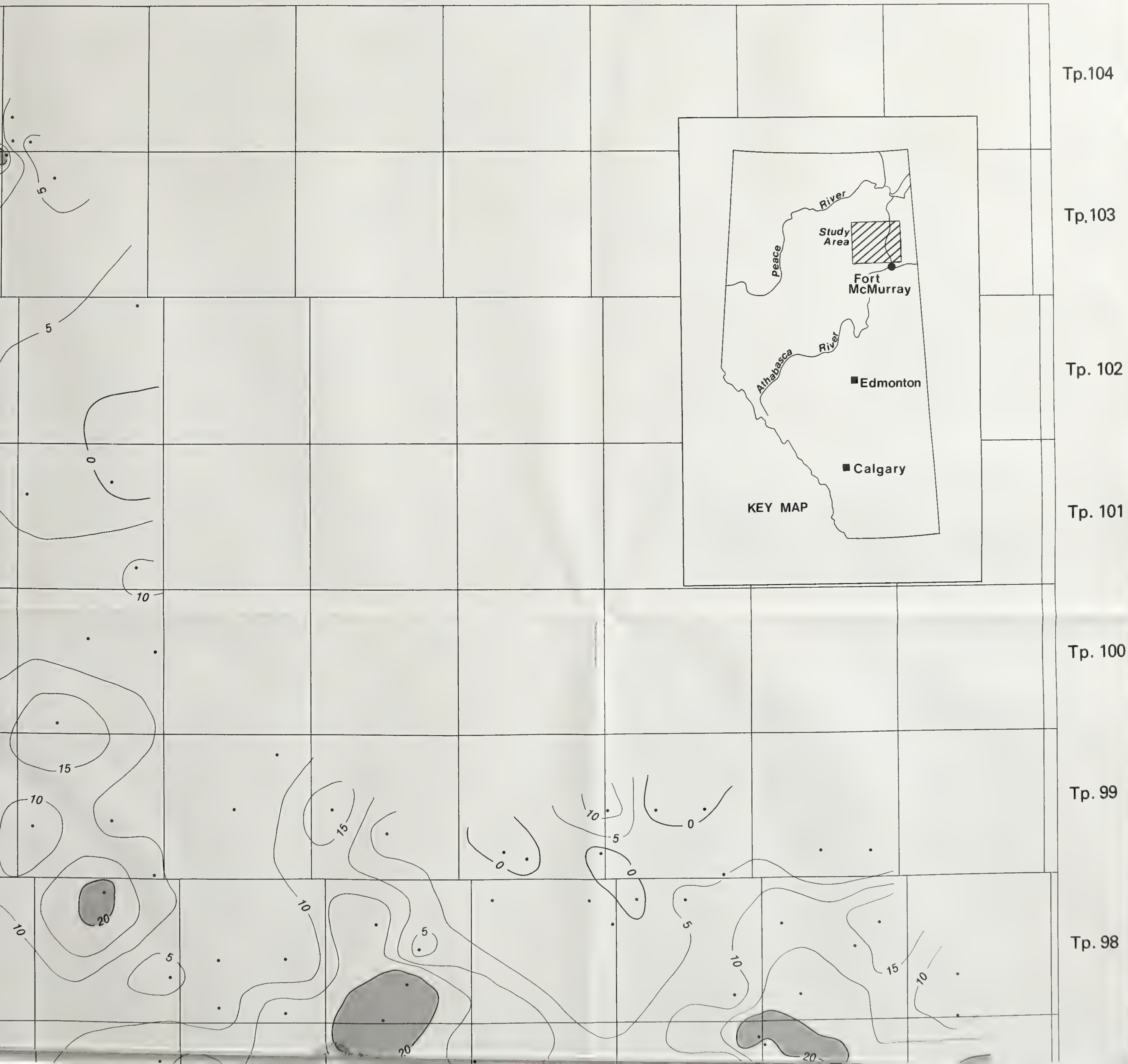
>20 m of uninterrupted pay

• Well control

Contour interval 5 metres



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Tp.103
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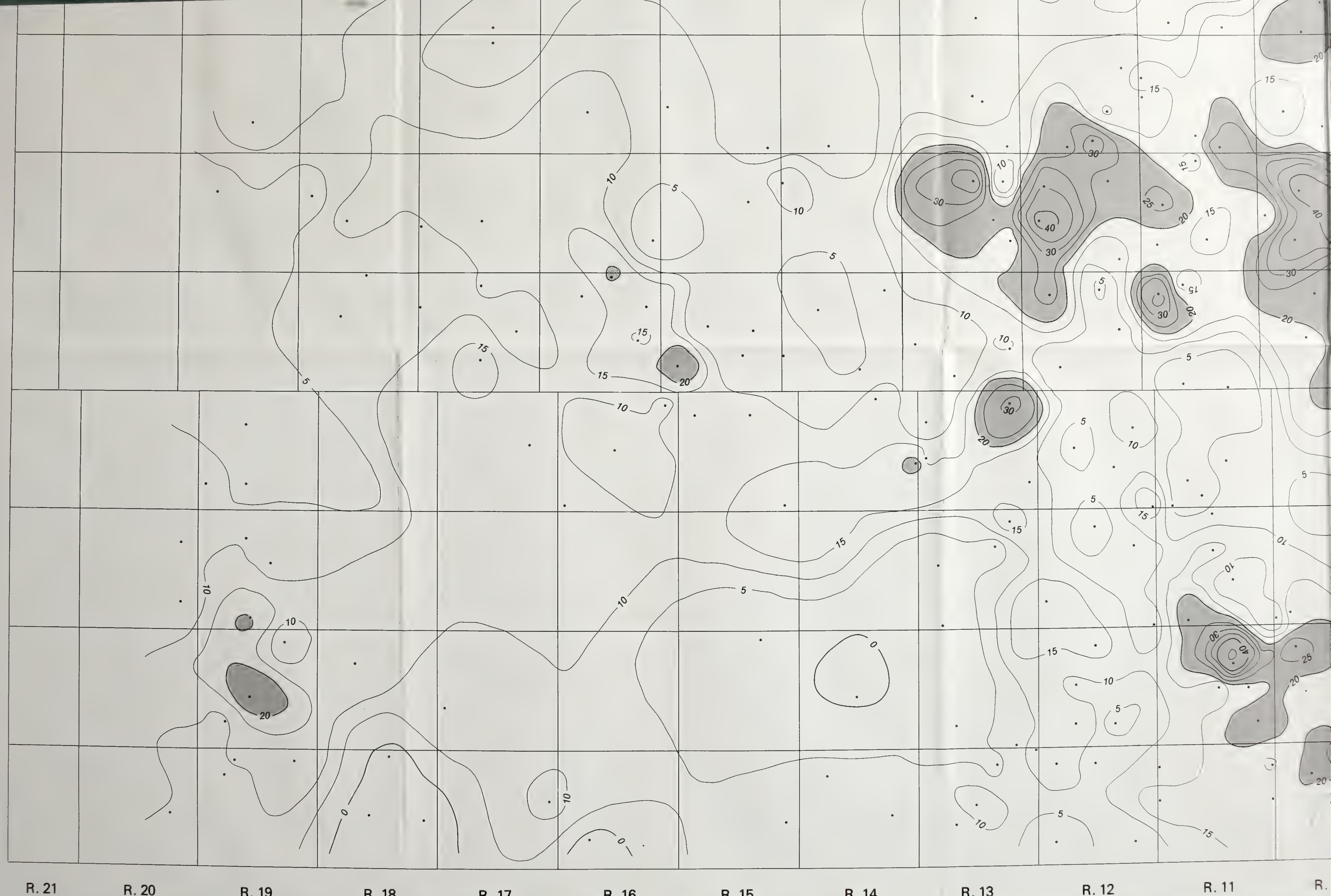
Tp. 100
Tp. 99
Tp. 98
Peace River
Study Area
Fort McMurray
Athabasca River
Edmonton
Calgary
KEY MAP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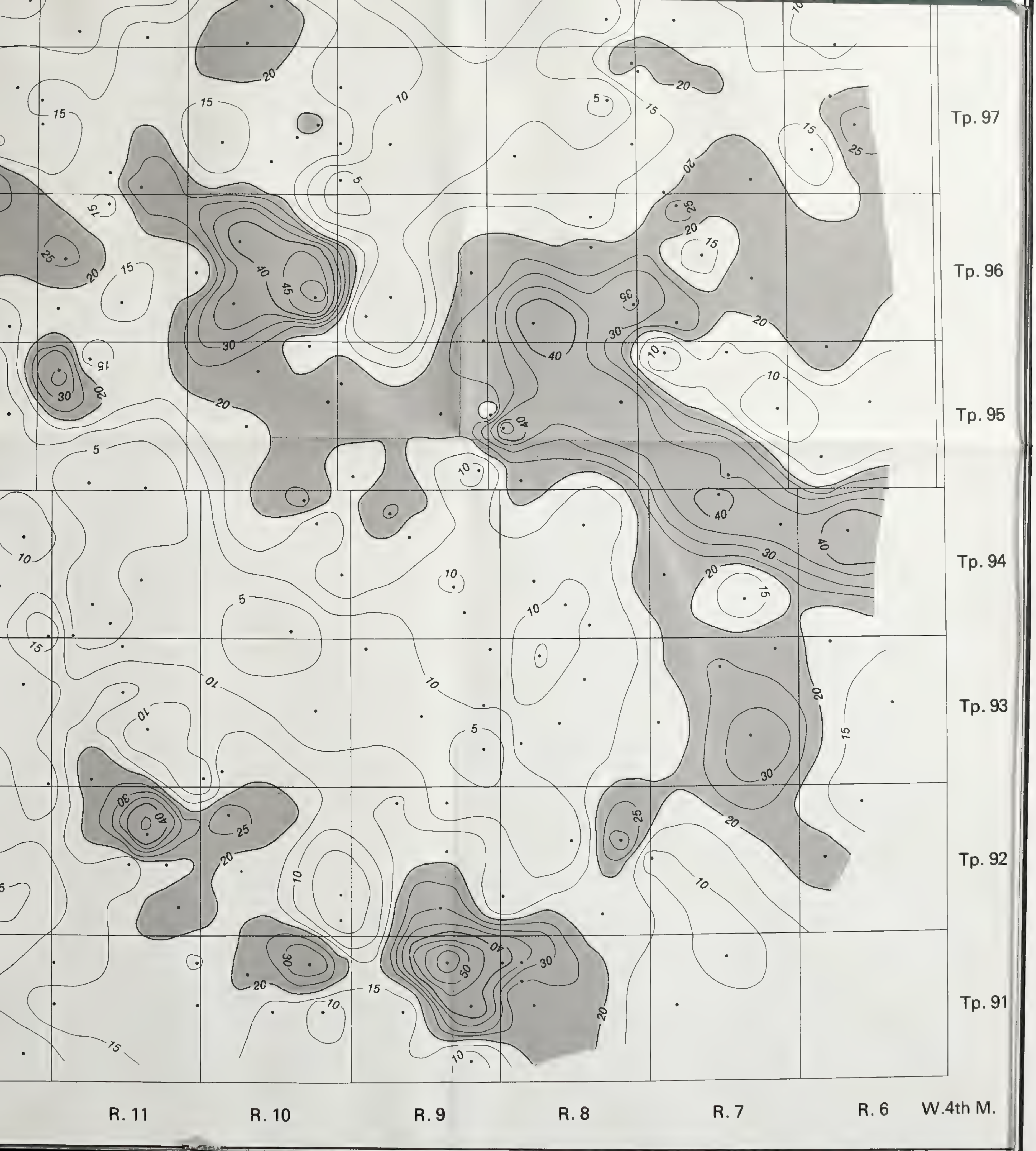
R. 12
R. 11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Tp. 93
Tp. 92
Tp. 91
R. 11
R. 10
R. 9
R. 8
R. 7
R. 6
W.4th M.

Bottom Water Sand Thickness
Athabasca Oil Sands North

Map 8

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SCALE 1:250,000

Kilometres 5 0 5 10 15 20 25 30 Kilometres

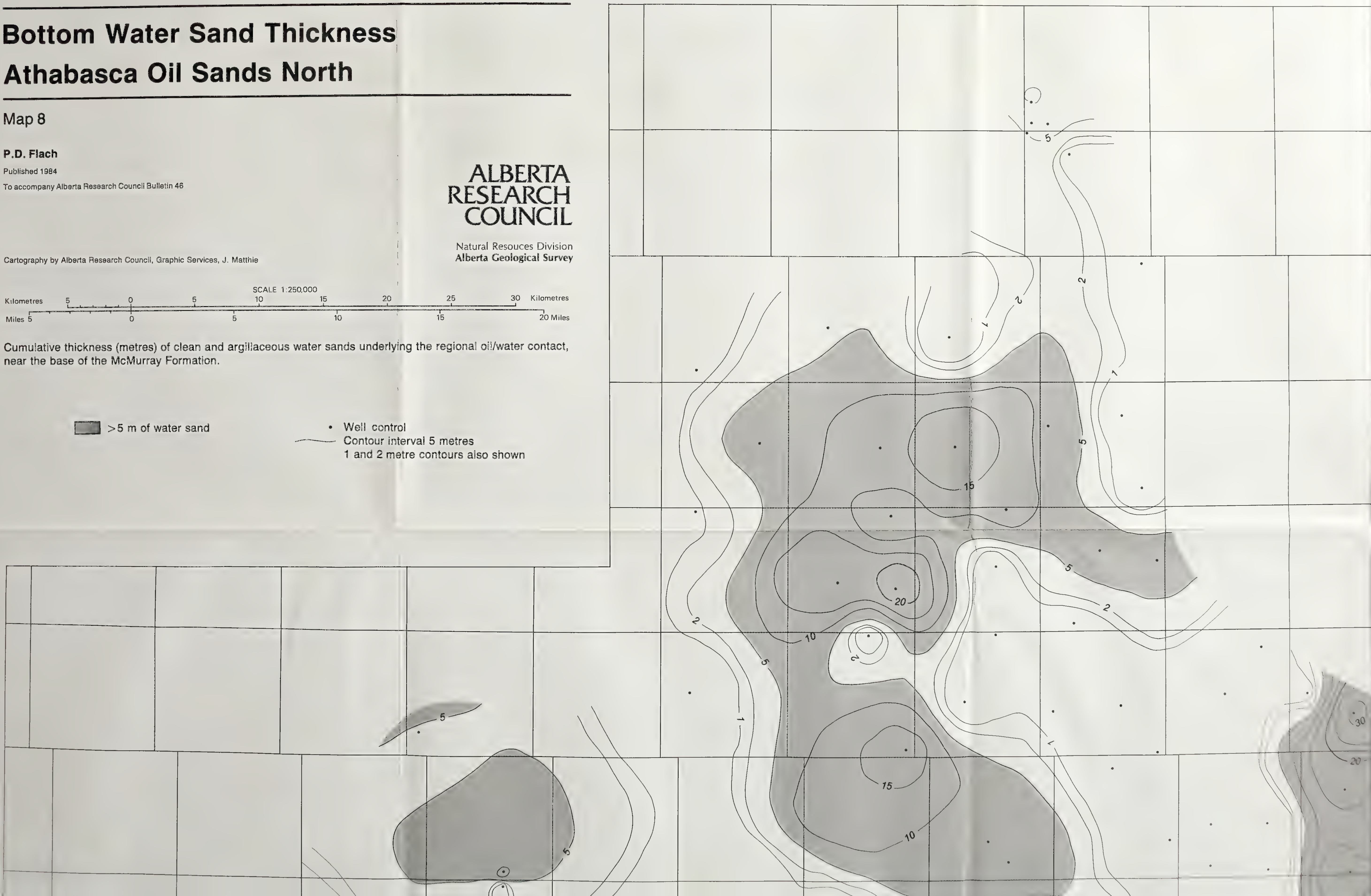
Miles 5 0 5 10 15 20 Miles

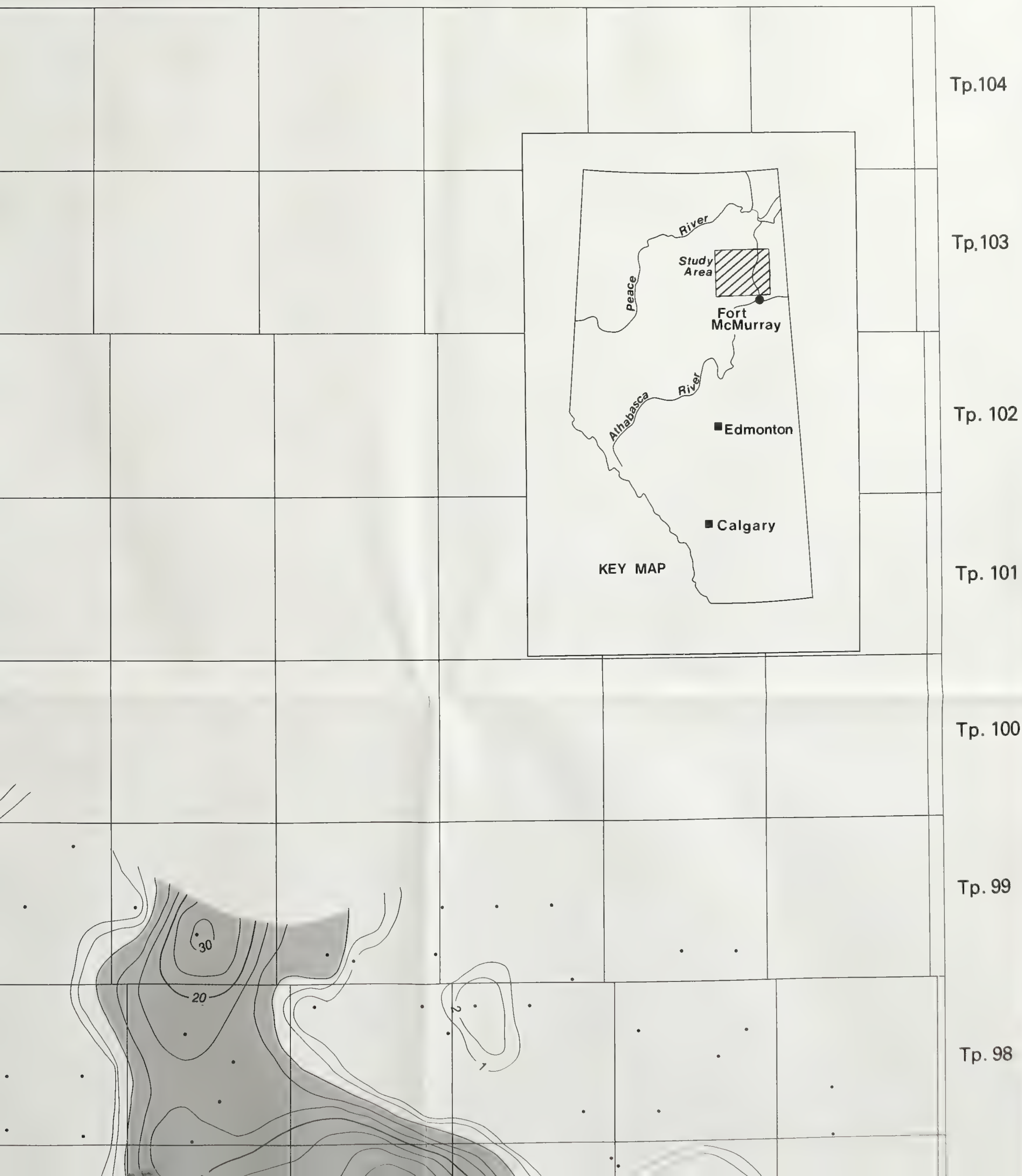
Cumulative thickness (metres) of clean and argillaceous water sands underlying the regional oil/water contact, near the base of the McMurray Formation.

>5 m of water sand

• Well control

Contour interval 5 metres
1 and 2 metre contours also shown

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Tp.103
Tp. 102
Tp. 101
Tp. 100
Tp. 99
Tp. 98
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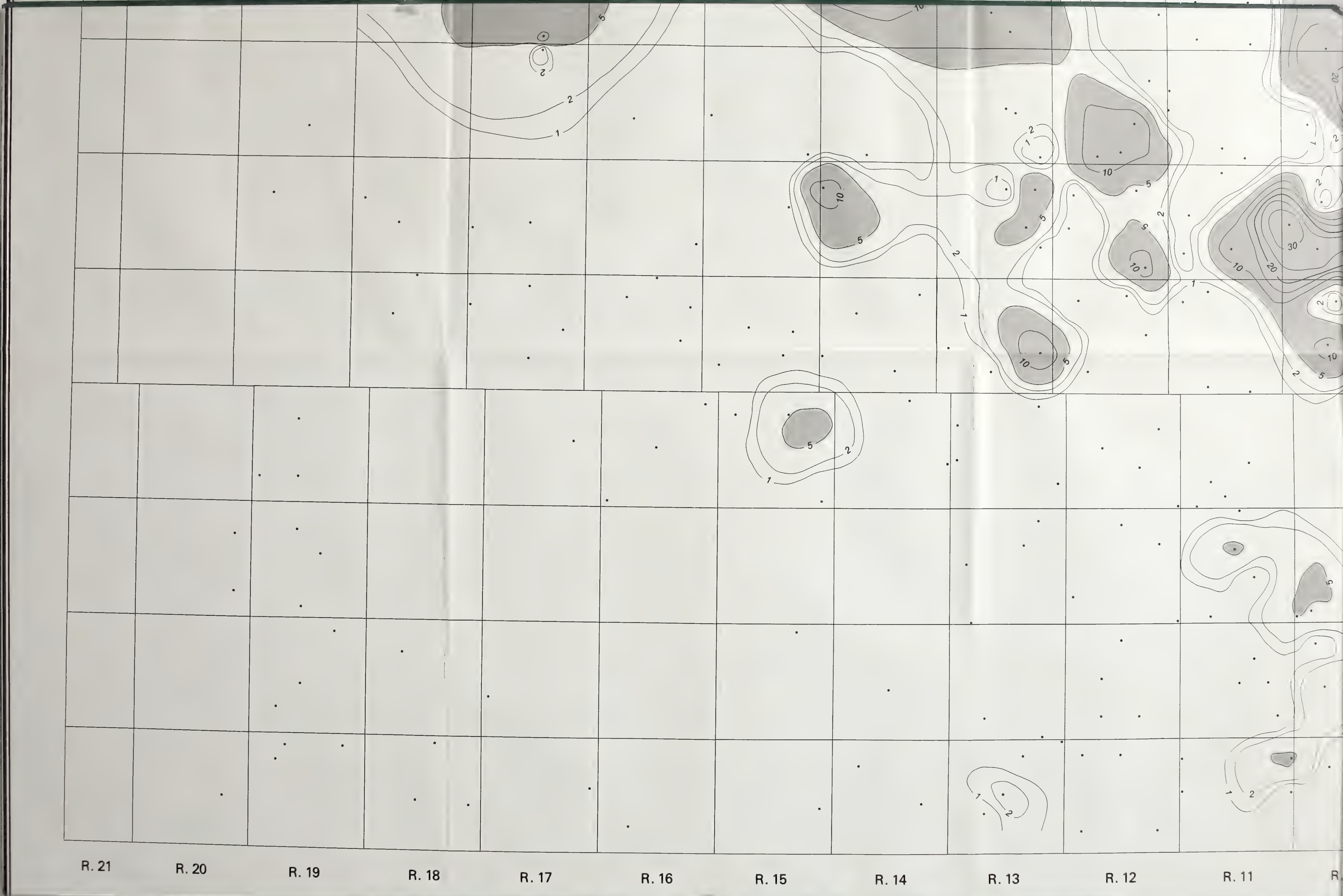
Peace
Study Area
Fort McMurray
Athabasca
River
Edmonton
Calgary
KEY MAP
30
20
2
1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R. 16
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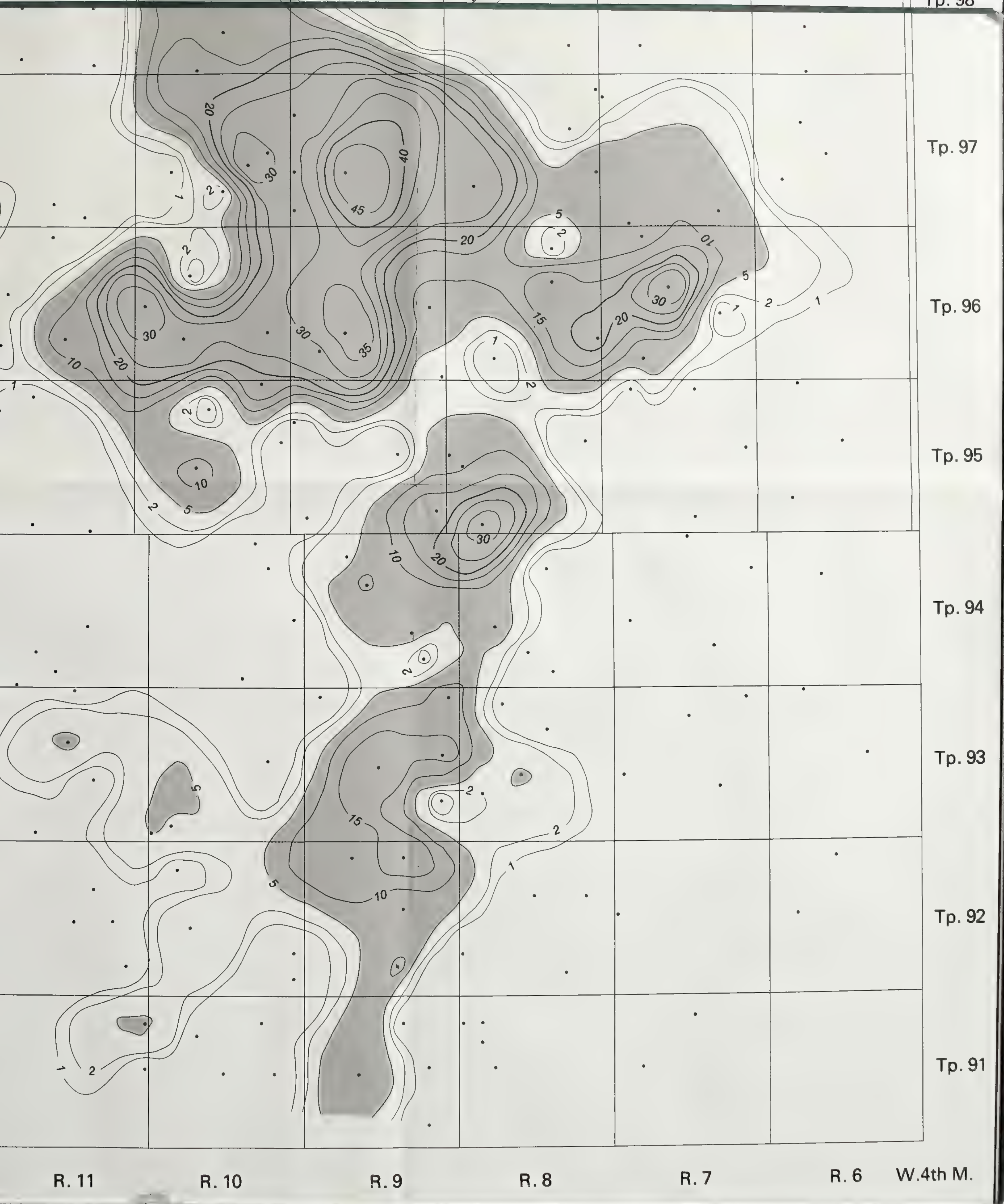
R. 14
R. 13
R. 12
R. 11



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Tp. 95
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Tp. 93
Tp. 92
Tp. 91
R. 11
R. 10
R. 9
R. 8
R. 7
R. 6
W.4th M.

Overburden Thickness
Athabasca Oil Sands North

Map 9

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SCALE 1:250,000

Kilometres 5 0 5 10 15 20 25 30 Kilometres

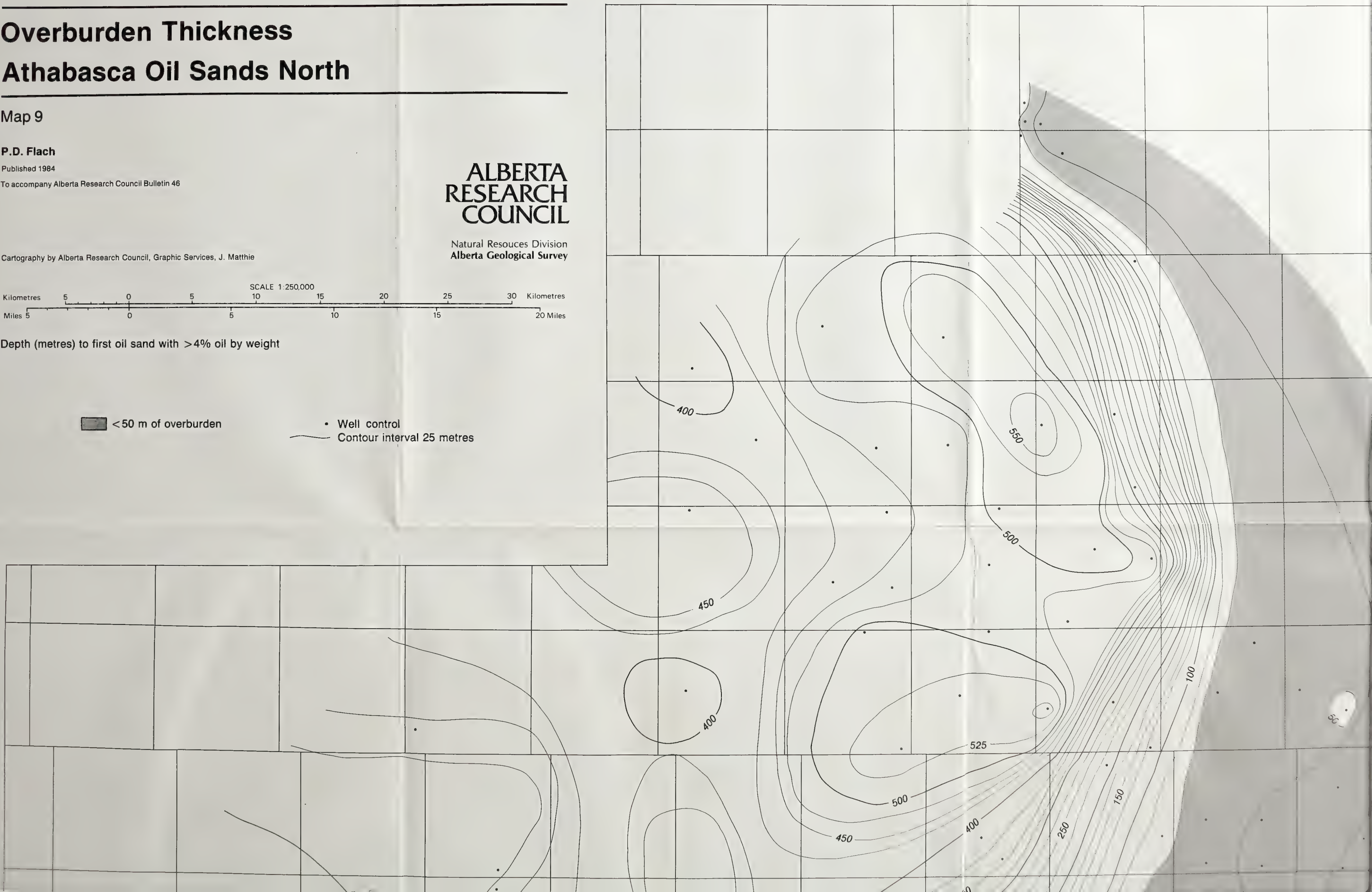
Miles 5 0 5 10 15 20 Miles

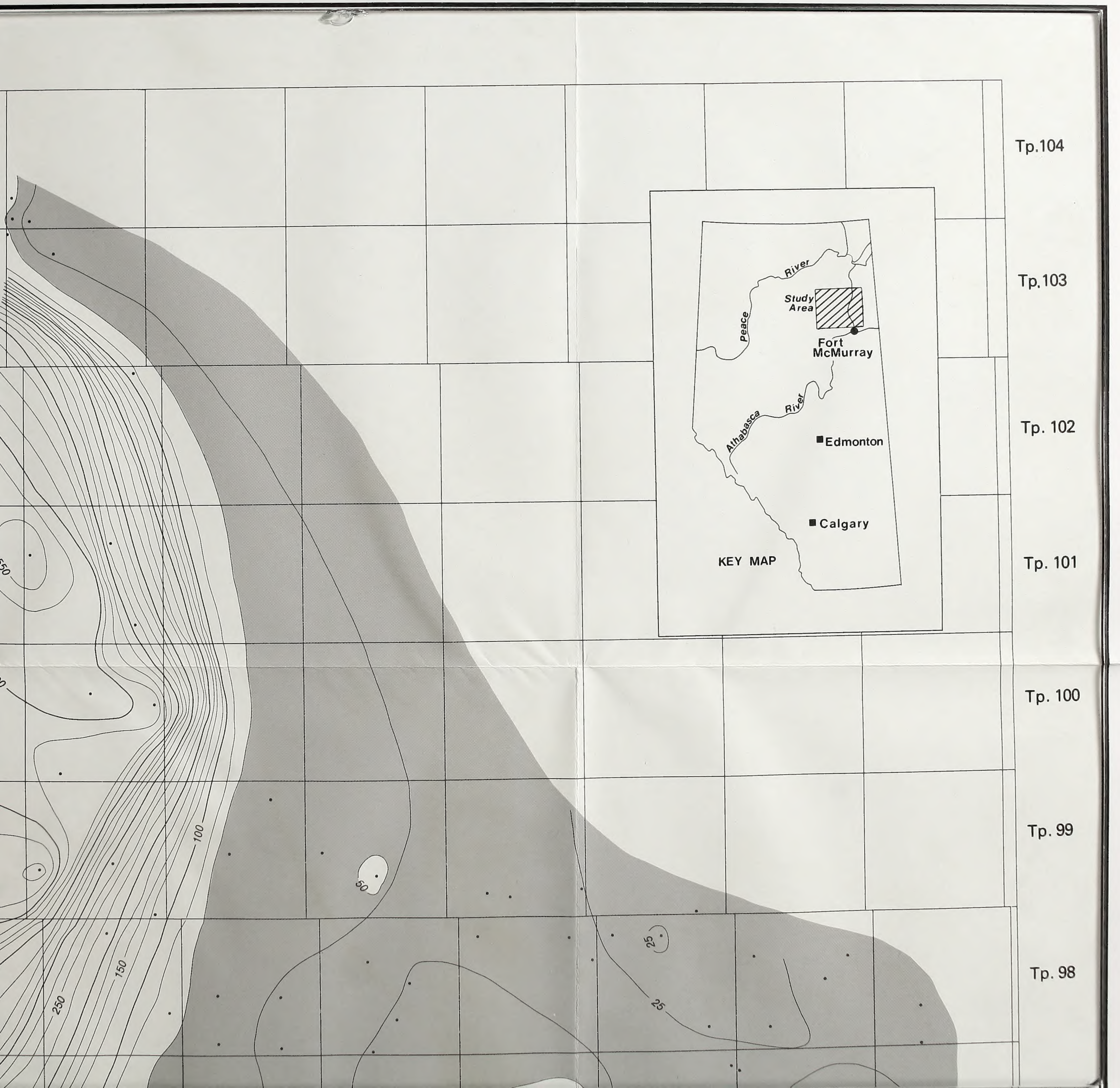
Depth (metres) to first oil sand with >4% oil by weight

▒ <50 m of overburden

• Well control

—— Contour interval 25 metres





Tp.104
Tp.103
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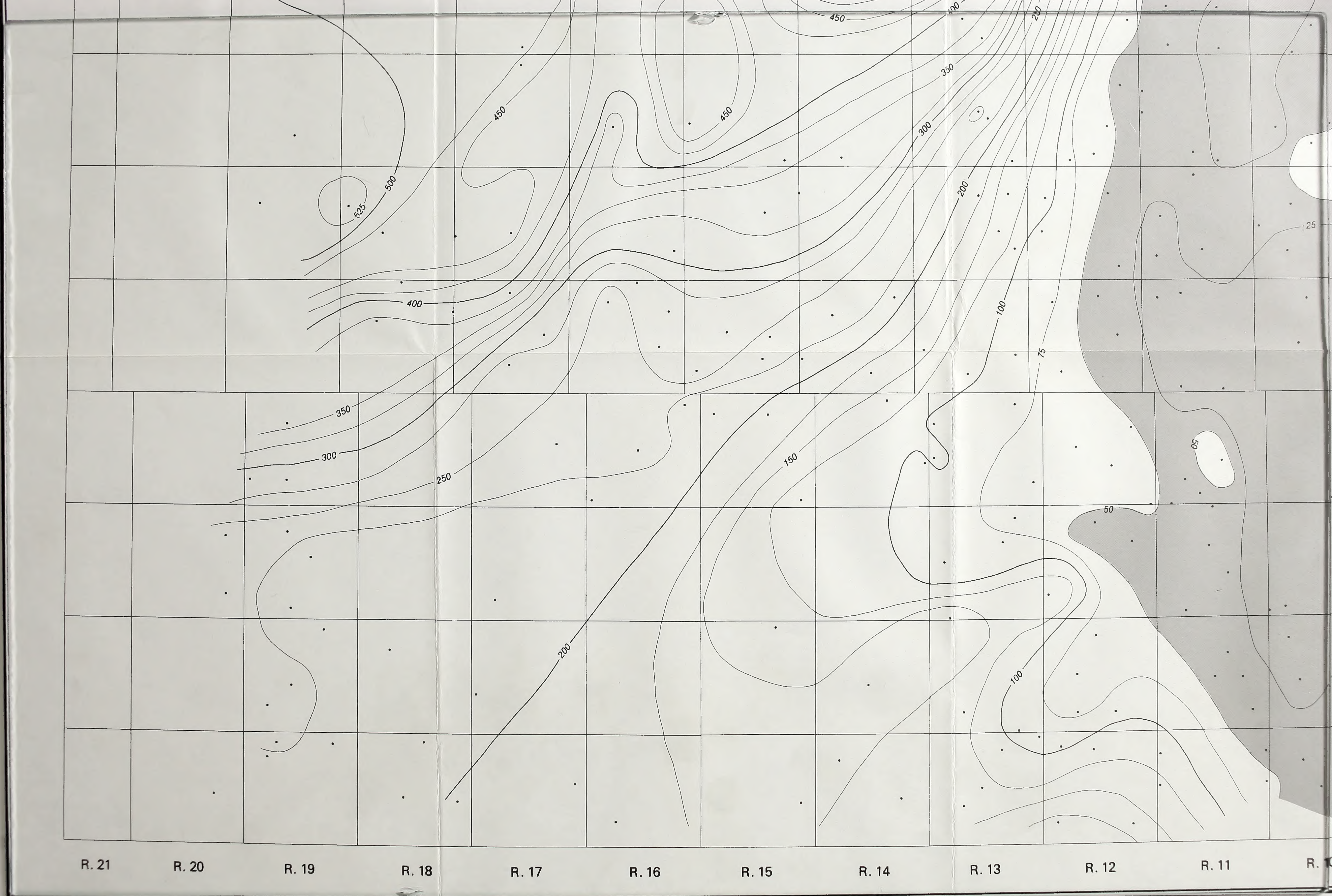
Tp. 101
Tp. 100
Tp. 99
Tp. 98
River
Study Area
Peace
Fort McMurray
Athabasca
River
Edmonton
Calgary
KEY MAP
550
100
50
25
25
150
250



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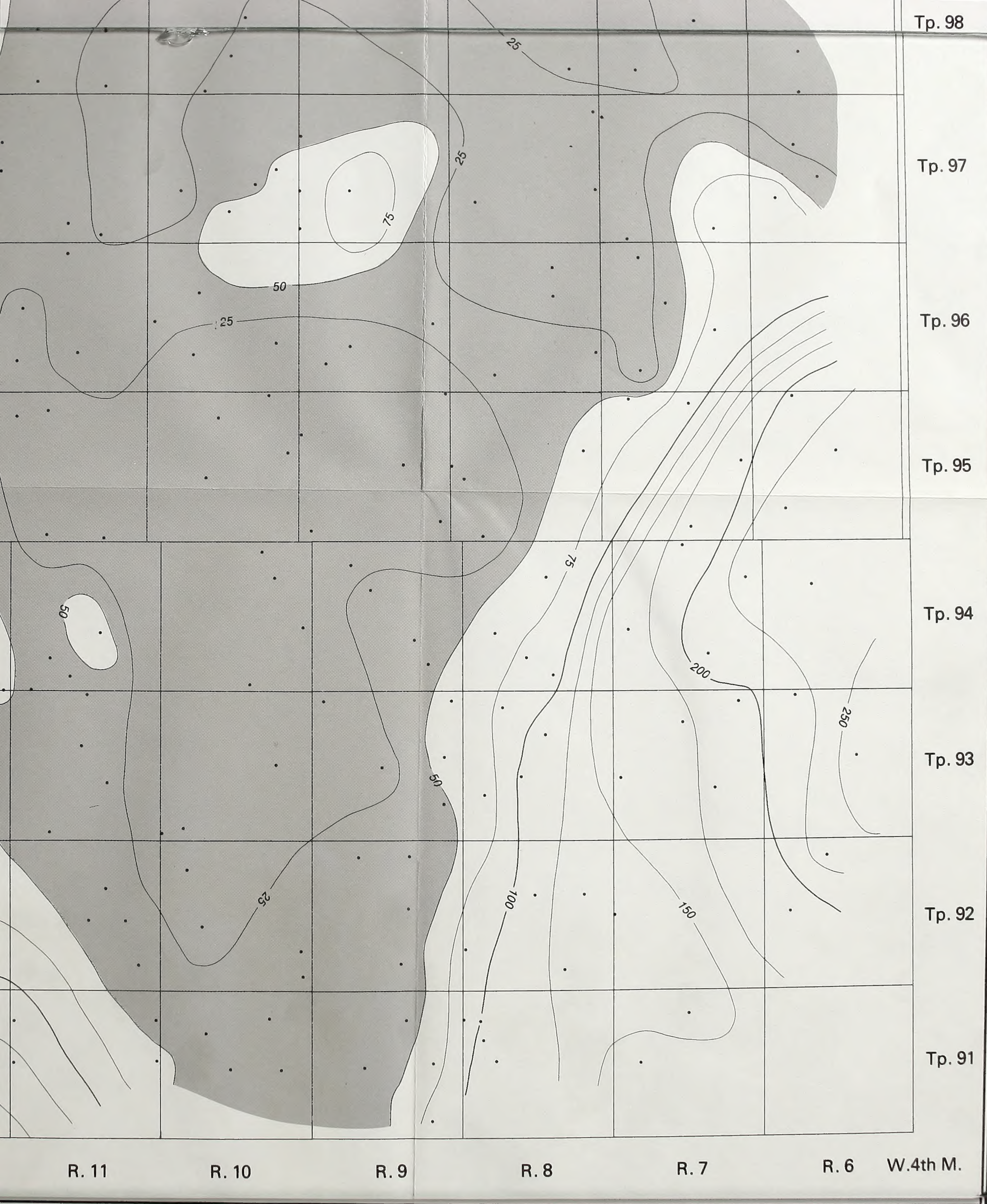
R. 14
R. 13
R. 12
R. 11
R. 10



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Tp. 93
Tp. 92
Tp. 91
R. 11
R. 10
R. 9
R. 8
R. 7
R. 6
W.4th M.
25
50
75
100
150
200
250